ieso
Power to Ontario.

Independent Electricity System Operator
655 Bay Street
Suite 410, PO Box 1
Toronto, Ontario M5G 2K4
t 416 506 2800
www.ieso.ca

BY COURIER AND RESS

November 7, 2007

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms Walli:

Re: Ontario Power Generation Inc.
Application for Reliability Must Run Contract for Lennox G.S.
Board File Number EB-2007-0715

Please find the Independent Electricity System Operator's interrogatory responses to Board staff attached.

Yours truly,

David Short, P.Eng.
Senior Regulatory Analyst
Regulatory Affairs
Independent Electricity System Operator

Encl.

c: Andrew Barrett, OPG – email only
Intervenors – email only

Ontario Energy Board (Board Staff) Interrogatory #1

Interrogatory

Re: Appendix D – Formal De-registration Correspondence between OPG and IESO

Under sections 2.4 and 9.6 of Chapter 7 of the Market Rules, a technical assessment must be performed by the IESO to support a decision to enter into an RMR agreement.

a. Please file the technical assessment conducted by the IESO under the Market Rules and which is the basis for entering into the 2007-08 RMR Agreement.

b. Please confirm that that this study is the one referenced in the letter dated April 5, 2007 from Mr. Finkbeiner of the IESO to Mr. Barrett of OPG.

Response

a. Please see the attached document "Lennox GS Deregistration Analysis" dated May 11, 2007 in Exhibit A.

b. Yes, the study referenced in Mr. Finkbeiner's letter is the study referenced in 'a.' above. While the study was completed prior to the date of Mr. Finkbeiner's letter, the IESO's final report was not issued until May 11, 2007.

Ontario Energy Board (Board Staff) Interrogatory #2

Interrogatory

Re: Appendix D – Formal De-registration Correspondence between OPG and IESO

Section 9.6.7.2 of the Market Rules permits the IESO to negotiate a contract with a "single potential supplier where the IESO determines this will result in reasonable prices and other terms".

a. Has the IESO ever attempted to employ a competitive tendering or negotiation process with multiple potential suppliers to deal with the identified reliability issues?

b. If not, why not?

Response

a. No, the IESO has not attempted a competitive process for the reasons described below in our response to b.

b. The IESO deemed it impractical to enter into a competitive process for the procurement of a similar quantity of generation capacity (~2GW) in this local area because of the availability of comparable alternatives and the permitted duration of the contract term.

Ontario Energy Board (Board Staff) Interrogatory #3

Interrogatory

Re: Appendix D – Formal De-registration Correspondence between OPG and IESO

The Integrated Power System Plan (the "IPSP") filed with the Board in August 2007 by the Ontario Power Authority (the "OPA") (proceeding EB-2007-0707) assumes that Lennox will remain in service for local reliability reasons at least through 2010. Attached as Attachment A to these interrogatories are copies of the relevant IPSP materials filed by the OPA. Page 9 of Exhibit D, Tab 8, Schedule 1 ("Natural Gas Fired Resources') deals with the OPA's assumptions about the need for and operation of Lennox. Attachment 1 to Exhibit D, Tab 8, Schedule 1 ("Discussion Of The Ongoing Requirement For The Availability Of The Lennox Generating Station And The Cost Effectiveness Of Alternatives") provides a more detailed analysis.

a. Does the IESO share the OPA's view that Lennox will be needed to operate as a must-run facility for system reliability purposes until at least the end of 2010?

b. Has the IESO done an analysis of whether a multi-year RMR agreement for Lennox could result in a more reasonable cost and/or provide superior incentives to OPG to manage investment in and the operation of Lennox while it is needed as a must-run facility?

Response

a. The extent of the IESO's studies to-date that represent the IESO's view on the need for Lennox are reported in our May 11, 2007 Lennox GS Deregistration Analysis and the September 10, 2007 Ontario Reliability Outlook:

   From the Lennox Deregistration Analysis: (Pages 1-2)
   The results show that all 4 units at Lennox are required for the purposes of reliability during the period Oct 2007 to Sep 2008. The new generation capacities at Goreway and Portlands, scheduled to go in service during the study period may reduce the number of Lennox units required to control flows from the west towards Toronto, but cannot control voltages in eastern Ontario as effectively as Lennox, to support the expected peak flows towards Ottawa. The total generation capacity expected to come into service at Goreway and Portlands (in the GTA, east of FETT) can only replace one Lennox unit. However, given the risk of delays to generation projects, it is recommended to contract all four Lennox units for the whole study period.

At the present time, the transfer capability to the Ottawa area is highly dependent on the number of Lennox units in service. More than two units are required to realize additional benefits by arming local load rejection. Under extreme winter conditions the FIO can go as high as 1950MW which, under certain outage conditions, requires all four Lennox units and a significant amount of load rejection armed in Ottawa to reliably supply the expected peak flows to the Ottawa area. The future grid enhancements associated with the new tie and HVDC connection with Hydro Quebec are expected to improve the transfer capability to the Ottawa area, but these enhancements are not expected before the end of 2009.

From the September 10, 2007 18-Month Outlook: (Page 28)
Studies performed by the IESO indicated that there could be significant adverse local area reliability impacts if Lennox is removed from the IESO-controlled grid and the IESO-administered markets without adequate replacement. When the new interconnection with Québec is completed (outside the timeframe of this Outlook), the resulting transmission improvements in the Ottawa area may reduce its reliance on Lennox for the local area need. However, the capability of the station is critical to provincial resource adequacy and must be retained or replaced. This resource adequacy requirement cannot be achieved through an RMR under the current Market Rules. The OPA has notified the IESO that it will undertake development of a solution to the Lennox requirements.

b. As the Market Rules (Chapter 7, Section 9.7.1.1) restrict reliability must run contract terms to one-year or less, we did not investigate longer-term solutions. However, the IESO has advised the Ontario Power Authority to consider other possible solutions that would eliminate the longer-term requirement for reliability must run contracts for the Lennox generating station.

Ontario Energy Board (Board Staff) Interrogatory #4

Interrogatory

Re: Section 4.4 of the 2007-08 Agreement

Section 4.4.1 of the 2007-08 RMR Agreement provides for the IESO to initiate one or more audits during the term of the RMR Agreement and within a period of four months from the expiration or termination of the RMR Agreement, to verify compliance by OPG with its obligations under the RMR Agreement, including verification of billings and costs.

a. Please identify if the IESO is, or will be, arranging for or conducting an independent audit of OPG's performance under the second RMR agreement?

b. If available, please provide information on the results of such an audit.

Response

a. An independent audit initiated by the IESO was conducted recently in the fall of 2007.

b. The results of the audit are not yet available; however, the IESO will endeavor to provide the auditor's Executive Summary and Conclusions prior to November 30, 2007.

Filed: November 7, 2007
EB-2007-0715
IESO Responses
Exhibit A for Interrogatory #1

Power to Ontario.
On Demand.

REPORT

Lennox GS Deregistration Analysis

Independent Electricity System Operator

Issue 2.0

Final REPORT

Project: Lennox GS Reliability Must Run Contract
Period: October 2007 to September 2008

Transmission Assessments & Performance Department

May 11, 2007

Disclaimer

Document ID	IESO_REP_0393
Document Name	Lennox GS Deregistration Analysis
Issue	Issue 2.0
Reason for Issue	Support Lennox RMR for period Oct 2007 to Sep 2008
Effective Date	May 11, 2007

Document Change History

Issue	Reason for Issue	Date
1.0	Internal release - confidential	March 21, 2007
2.0	External release - public	May 11, 2007

Related Documents

Document ID	Document Title

Table of Contents

List of Figures

List of Tables

Table of Changes

Reference (Section and Paragraph)	Description of Change

1. Lennox Deregistration Analysis – summary

Ontario Power Generation (OPG) has requested that operation of Lennox Thermal Generation Station (TGS) be discontinued and that all generation facilities at Lennox be de-registered by October 1, 2007, for economic reasons. This study covers the October 2007 to September 2008 period and was performed to identify the impact of deregistering Lennox TGS units on the reliability of the IESO-controlled grid to:

- Accommodate expected peak flows to the Ottawa area,
- Accommodate expected peak flows towards Toronto from the west,
- Provide sufficient reactive resources and adequately control voltages in the Greater Toronto area, and eastern Ontario including the Ottawa area.

Lennox TGS is geographically located near Kingston, Ontario and represents over 50% of the total generation capacity in the East[1] zone - 2200MW out of 4396MW. Lennox TGS's electrical location provides a variety of benefits to the IESO Controlled Grid:

- Generation capacity on the load side of the congested transmission lines converging from the west towards Toronto (interface FETT – Flow East To Toronto).
- Dynamic voltage control for the GTA, eastern Ontario in general, and specifically the Ottawa area.
- Reliable supply to the Ottawa area.

Analysis of combined January 01, 2005 to March 15, 2007 data indicated that Lennox units were in service, supporting system reliability for 4495 hours, (23.3% of the time) with the plant at full capacity (4 units) for about 717 hours (3.7% of the time). During this time the Lennox units were brought in service to compensate for reduced hydro-electric generation in Northern Ontario, units at Pickering and Darlington taken out of service for maintenance, and for high load in the Ottawa zone.

This analysis took into account the future demand growth as published in the latest 18-Month Outlook, availability of hydro-electric generation and outage plans registered with the IESO. The results show that all 4 units at Lennox are required for the purposes of reliability during the period Oct 2007 to Sep 2008. The new generation capacities at Goreway and Portlands, scheduled to go in service during the study period may reduce the number of Lennox units required to control flows from the west towards Toronto, but cannot control voltages in eastern Ontario as effectively as Lennox, to support the expected peak flows towards Ottawa. The total generation capacity expected to come into service at Goreway and Portlands (in the GTA, east of FETT) can only replace one Lennox unit. However, given the risk of delays to generation projects, it is recommended to contract all four Lennox units for the whole study period.

At the present time, the transfer capability to the Ottawa area is highly dependent on the number of Lennox units in service. More than two units are required to realize additional benefits by arming

[1] East zone - as defined by the ten zone model of the Ontario system (see Figure 1).

local load rejection. Under extreme winter conditions the FIO can go as high as 1950MW which, under certain outage conditions, requires all four Lennox units and a significant amount of load rejection armed in Ottawa to reliably supply the expected peak flows to the Ottawa area. The future grid enhancements associated with the new tie and HVDC connection with Hydro Quebec are expected to improve the transfer capability to the Ottawa area, but these enhancements are not expected before the end of 2009.

– End of Section –

2. Conclusions and Recommendations

2.1 Conclusions

Lennox TGS is located at the heart of an area with a deficit of generation:

- The combined peak load of East and Ottawa zones is almost twice the available total generation, including Lennox.
- Lennox represents 50% of the installed generation capacity east of the Toronto zone[2], and taking this facility out of service would reduce the generation resources east of Toronto zone to the equivalent of about one quarter of the total peak load of this area.
- To compensate for this reduction, most of the energy must come from the west, from the other side of the GTA – the major load center of the province – increasingly stressing the Flow East To Toronto (FETT) and Flow Into Burlington (FIB) transmission paths that are already congested.

The Flow Into Ottawa (FIO) is approaching the transmission transfer limit during peak periods:

- The units at Lennox are providing key support for improving the transfer capability to supply Ottawa in a reliable manner. Without Lennox support up to more than 175 MW (at maximum) of load reduction would've been required in the Ottawa zone for up to 80 hours in the period Jan 01/2005 to Mar 15/2007.
- The future grid enhancements associated with new tie and HVDC connection with Hydro Quebec originally expected to go in service in Q4 2009 so it has no impact over the current study period.
- If Lennox units area decommissioned before completion of the transmission reinforcement, the extra 300 MW of FIO transfer limit provided by Lennox are lost, the resulting transfer capability may be insufficient to supply the Ottawa loads.

2.2 Recommendation

It is recommended to contract all four Lennox units from October 2007 to September 2008.

– End of Section –

[2] Pickering and Darlington are, according to the IESO ten zones definitions, located in the Toronto zone.

3. Introduction

3.1 Purpose

This study was performed to identify the impact of retiring Lennox TGS units on the reliability of the IESO-controlled grid to:

- Accommodate expected peak flows to the Ottawa area,
- Accommodate expected peak flows towards Toronto from the west,
- Provide sufficient reactive resources and adequately control voltages in the Greater Toronto area, and eastern Ontario including the Ottawa area.

3.2 Scope

The study assessed the need and identified the benefits of retaining Lennox GS for the period October 2007 to September 2008. This document outlines the technical considerations of this study, the benefits of Lennox TGS for the local area reliability, for reducing the congestion of FETT (Flow East To Toronto) and FIB (Flow Into Burlington) and the role of Lennox GS in providing reactive support and reliable supply to the Ottawa zone loads.

The study also provides a detailed analysis of operational data from January 01, 2005 to March 15, 2007.

– End of Section –

4. Major Assumptions

This study covers the period October 2007 to September 2008, and assessed the following conditions:

- Extreme weather demand forecast for winter 2007-2008 and summer 2008, as published in the latest 18 Month Outlook.
- All existing and committed generation and transmission projects in service.
- Generator outage plans as registered with the IESO to date.
- Hydro-electric generation availability forecast as per the latest IESO 18-Month Outlook.
- Typical FETT limit of 4900 MW during the summer (to account for transmission outages)

Operation of the IESO-controlled grid is illustrated by the ten-zone model shown in Figure 1 below (Ontario Zones, Interfaces and Interconnections).

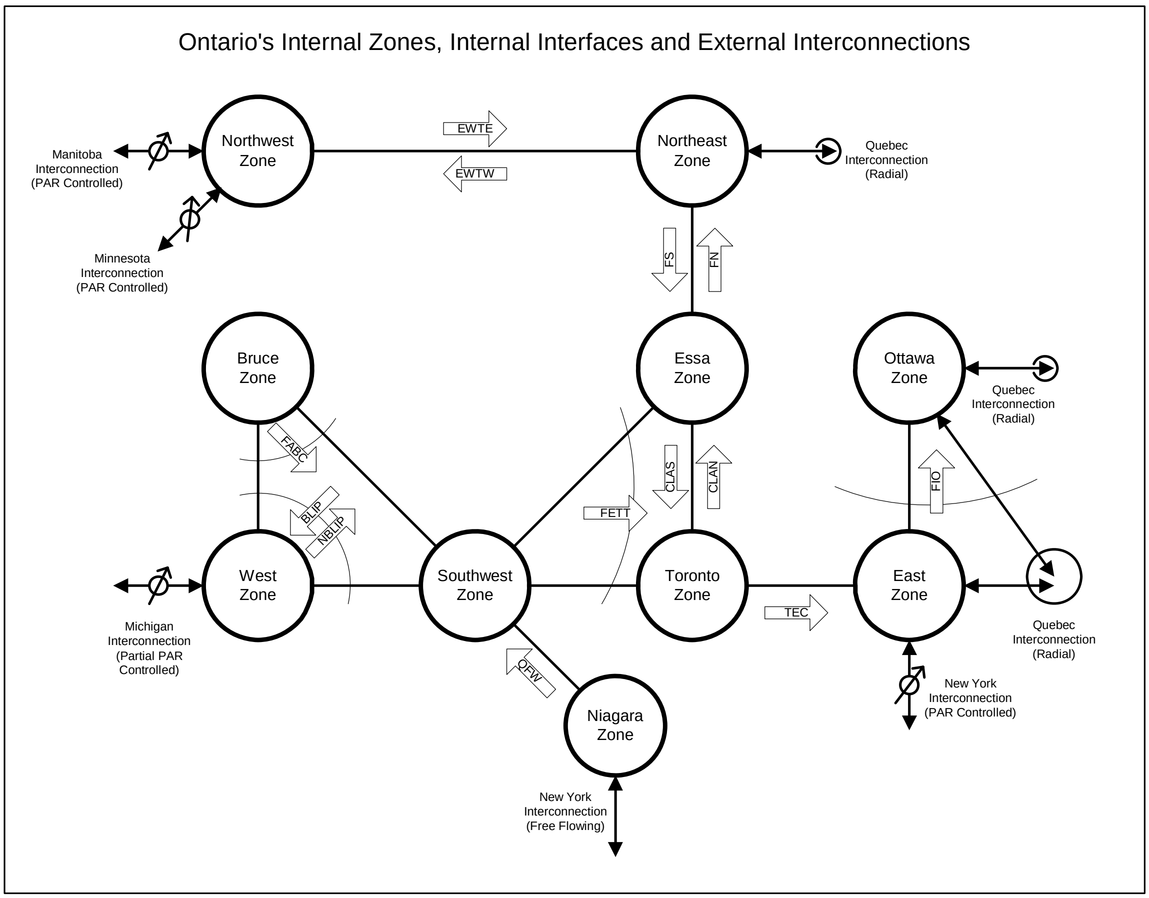

Figure 1: Ontario Zones, Interfaces and Interconnections

The highest demand in Ontario, over the last few years, was recorded in the summer and it generally coincides with the highest demand in the Toronto zone. This analysis was performed to determine the benefit of Lennox units for improving transfer limits and controlling the power flow in such a manner that expected demand can be supplied without security violations. The simulations were performed for the summer peak extreme weather demand forecast, with zero imports into Eastern Ontario from Quebec and zero flow at St. Lawrence. The results of these simulations were compared against pre and post contingency limits of the FETT and FIB interfaces. With all elements in service the pre-contingency flows were checked against continuous ratings and post-contingency flows against long-time emergency ratings and grid transfer limits. With any one element out of service the pre-contingency flows were checked against long-time emergency ratings, and post contingency flows against short-time emergency ratings.

Historically, the Ottawa zone reaches the highest demand during the winter season. Over the last two years, due to the warmer than normal weather, the highest demand in Ottawa was recorded during the summer when temperatures and humidex reached extreme[3] levels. To asses the impact of retiring Lennox units upon Ottawa zone electricity supply, simulations were performed for the winter peak demand under extreme weather conditions, with zero imports into Eastern Ontario from Quebec and zero flow at St. Laurence. With all elements in service the pre-contingency flows were compared against continuous ratings and grid transfer limits—the present Flow into Ottawa (FIO) transfer limit depends on the number of Lennox units in service—and post-contingency flows were compared against long-time emergency ratings.

– End of Section –

[3] Analysis of weather data from 1970 to 2007 for Ottawa zone indicated that Aug 01/06 scored number 2 out of 1147 readings from the temperature perspective (0.1% below extreme) and number 1 if the humidex is taken into consideration, which clearly indicates extreme weather conditions. For the same overall set of readings, on the low temperature scale, Feb 07/07 scored 46 out of 1073 readings which would place the coldest day of the study period about 4.28% above extreme.

5. Operational data analysis

5.1 General information

To reduce the uncertainty introduced by the weather factor the period starting January 01, 2005 to March 15, 2007 was analyzed to determine the Lennox benefits. This period was mainly chosen because Lennox was mostly under a reliability must-run contract.

The generation availability of the main units located east of FETT is summarized below:

Table 1: Major generation availability:

	Number of hours					
Number of units	Lennox	%	Pickering	%	Darlington	%
1	1814	9.4%	0	0.0%	0	0.0%
2	1343	7.0%	719	3.7%	411	2.1%
3	621	3.2%	3719	19.3%	6197	32.2%
4	717	3.7%	6514	33.8%	12664	65.7%
5	N/A	N/A	6215	32.2%	N/A	N/A
6	N/A	N/A	2105	10.9%	N/A	N/A
Total	4495	23.3%	19272	100.0%	19272	100.0%
Total hours =	19272					

During this time period the Ontario demand exceeded 20000 MW for 3818 hours, or 19.81% of the time. Lennox units were in service for 2397 (62.78%) of these hours, which would represent 53.33% of the total number of hours Lennox units were in service. It also should be noted that for 2098 hours, representing 46.67% of the number of hours Lennox units were in service, they helped support system reliability when total demand was lower than 20000 MW. The lowest was 12799 MW on the night of May 22-23, 2005 when 2 Lennox units were in service from May 22 @ 22:00 to May 23 @ 14:00, for 17 consecutive hours. This shows that Lennox support was required more often than just during high demand periods, as illustrated by the following figure:

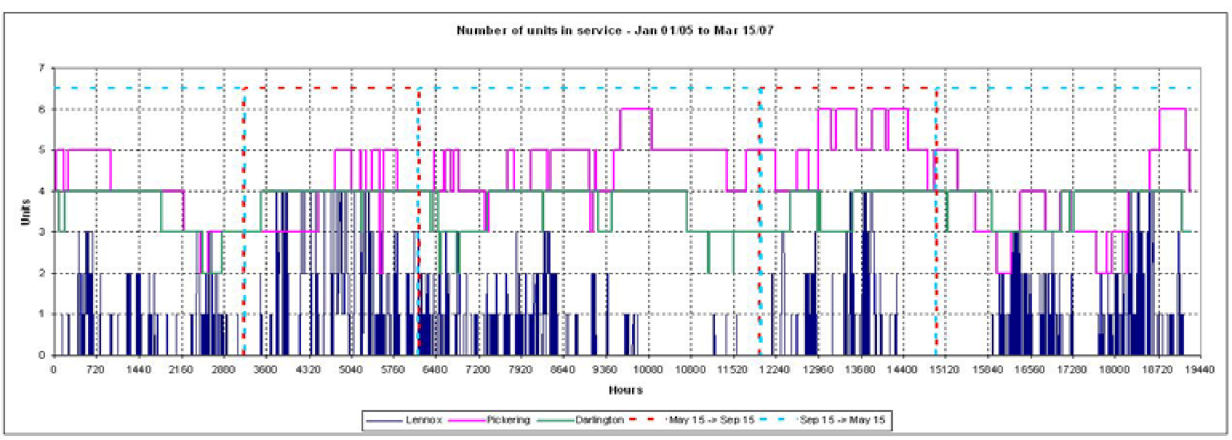

Figure 2: Pickering, Darlington and Lennox - number of units in service

Lennox units were required during all seasons to provide active power support, reactive and voltage support and to maintain grid reliability when units at Pickering and Darlington were taken off-line for maintenance.

The above graph also shows that Lennox was used less during summer 2006 than 2005. One reason for this reduction appears to be the availability of 6 units at Pickering. But this difference is also caused by milder overall weather, reflected in the average monthly temperature:

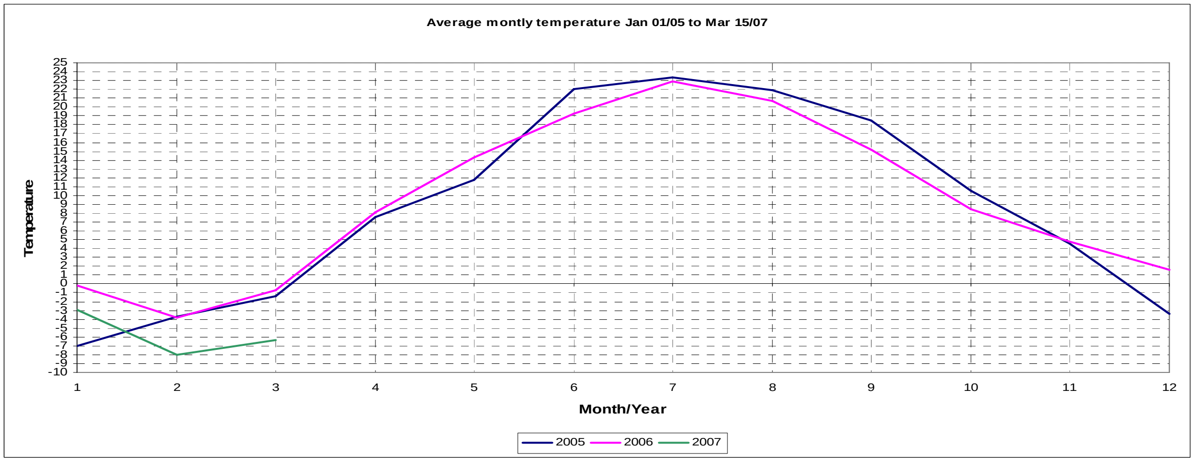

Figure 3: Average monthly temperature comparison

Summer 2005 was overall warmer than summer 2006 which caused higher average demands and as a result required more Lennox contribution:

Table 2: Average demand comparison

Average demand:	Yearly (MW)	Summer (MW)
2005	17911	18274
2006	17231	17531

An analysis of individual components of Lennox contribution show that the active power support for up to four units was required in the whole temperature range, but mostly during the warm season:

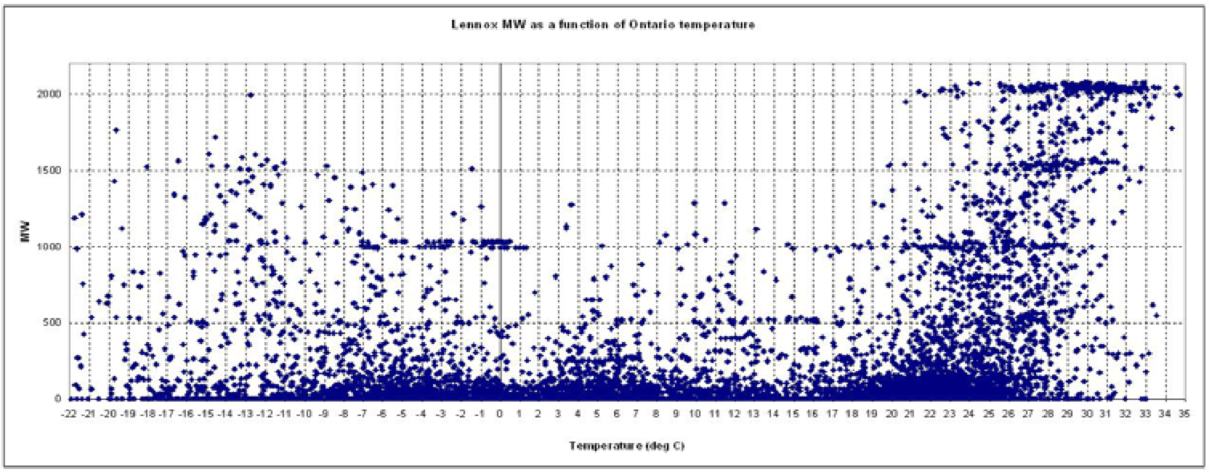

Figure 4: Lennox MW output dependency on temperature

The reactive support from Lennox was also required for the whole temperature range:

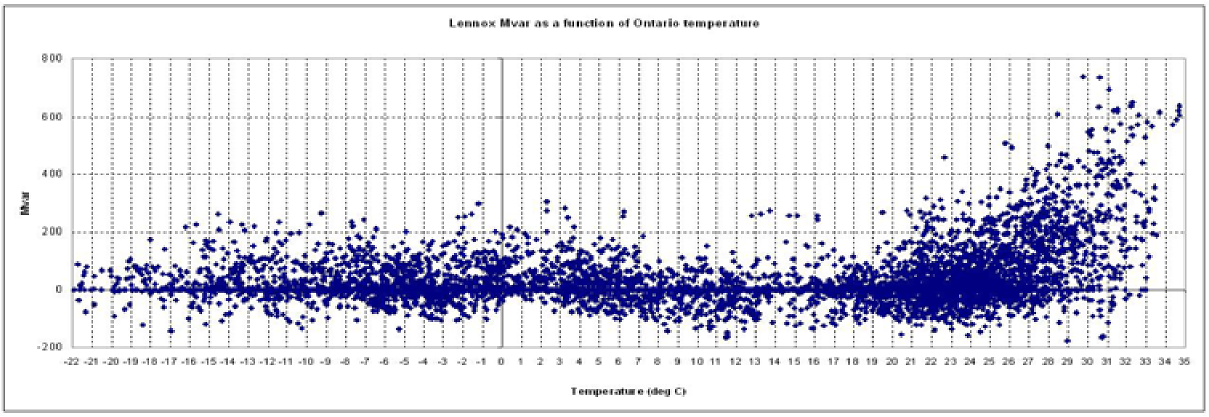

Figure 5: Lennox reactive output dependency on Ontario temperature

The above figure shows that reactive support of up to two units was required through the whole temperature range. As the temperature goes above 25 deg C the reactive support of the third and fourth units is more and more required, which is consistent with the type of load (inductive – air conditioners) that significantly increases over that temperature range. The same tendency can be seen at Pickering and Darlington:

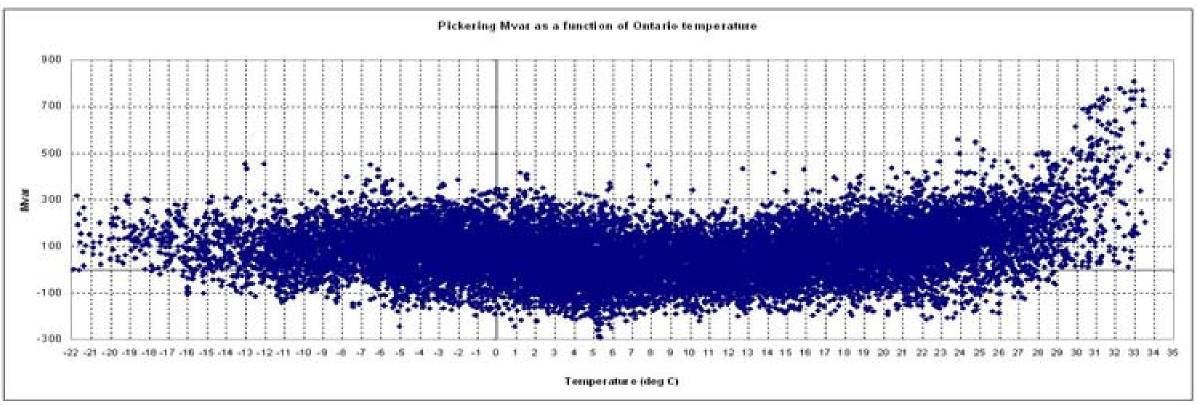

Figure 6: Pickering reactive output dependency on Ontario temperature

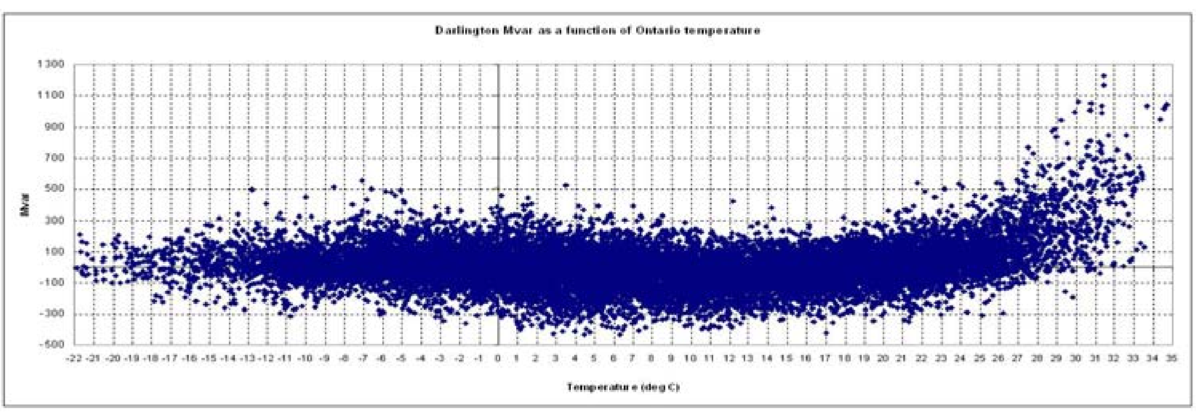

Figure 7: Darlington reactive output dependency on Ontario temperature

As base load plants, Pickering and Darlington are consistently providing voltage support. For temperatures over 30 deg C both Pickering and Darlington are providing significant voltage support to the system by generating reactive power which shows that other reactive resources in the system are fully utilized. Lennox output also goes consistently higher over 30 deg C confirming that for this temperature range the synchronous generators represent a critical source of reactive supply and voltage control for grid reliability. During the study period the temperature was over 30 deg C for 200 hours (1.04% of the whole period), over 25 deg C for 1125 hours (5.84% of the whole period).

5.2 Capacity for Congestion Control – Interface FETT (Flow East To Toronto) and FIB (Flow Into Burlington)

The distribution of load in Ontario is such that about 56% of the load is east of congested transmission paths between Hamilton and Toronto (FETT – Flow East to Toronto) and south of the circuits connecting northern and southern Ontario (FS – Flow South). However, about 55% of the generation is located west of the FETT interface. In addition, all of Ontario's import capability from Michigan and New York is located west of FETT.

When the combination of load and generation is such that these interfaces are congested, generating capacity east of FETT and south of FS is required to control the congestion and continue to supply the loads. If insufficient generation is available east and south of the congestion, emergency measures such as voltage reduction and if necessary rotational load shedding must be implemented to control the congestion.

The following figure shows how the FETT flow was controlled by Lennox generation and imports from Quebec and St. Lawrence during the study period. FETT spare capacity, shown below, is the difference between the hourly FETT transfer limit, and the actual recorded flow. To assess the reliance on Lennox and imports to control flow, the FETT spare was reduced by subtracting the actual hourly amount of Lennox generation and energy imported from Quebec. The result shows that the spare capacity goes negative for a significant number of hours. This means that flows were being controlled, or "supported" by Lennox and imports, and without them, the demanded flows would have exceeded the available FETT transfer limit.

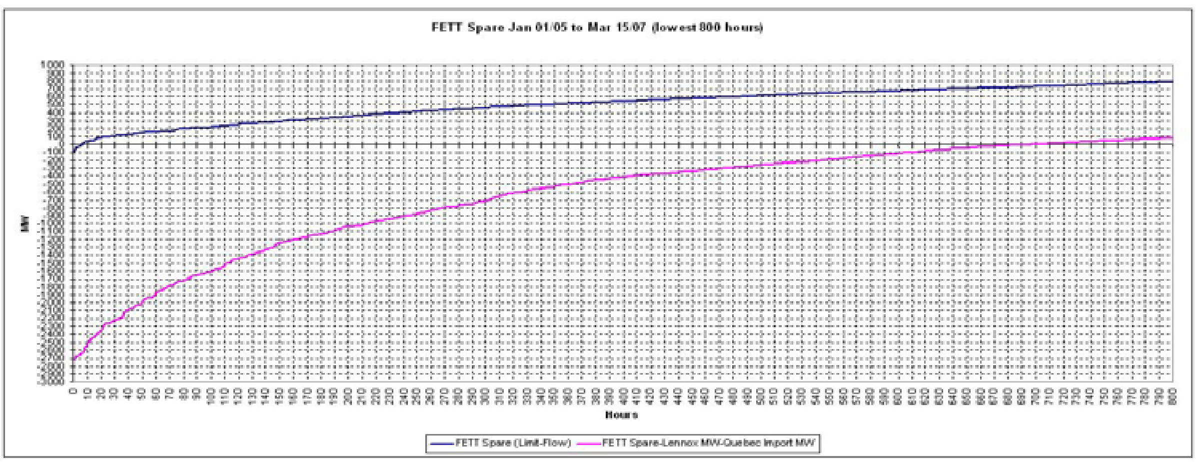

Figure 8: FETT spare - Jan 01/05 to Mar 15/07

The FETT was supported by Lennox generation and imports for 700 hours. Out of these, for a total of 32 hours the FETT spare relied on imports as the difference exceeds the maximum Lennox output. This pattern may change if Goreway and Portlands are beginning to generate, but part of the gross contribution is offset by the load growth in Toronto, East, and Ottawa zones.

Section 5.1. shows that Lennox support was mostly required in the warm season. Analysis of summer data over the study period shows that Lennox active support was clearly required when the demand in Toronto zone exceeded 9000 MW. This happened over 128 hours during summer 2005:

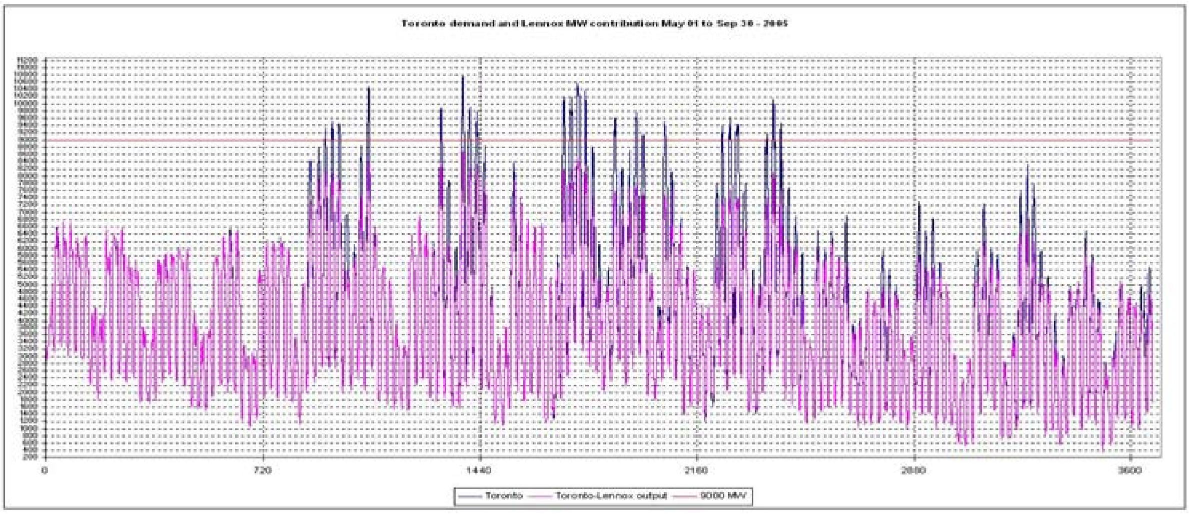

Figure 9: Lennox MW dependency on Toronto demand - summer 2005

Obviously, Lennox support was also required in other circumstances but the above figure shows that 9000 MW seems to be the threshold that was never exceeded without Lennox support.

Due to a lower average temperature in summer 2006, Toronto zone demand exceeded 9000 MW for only 78 hours:

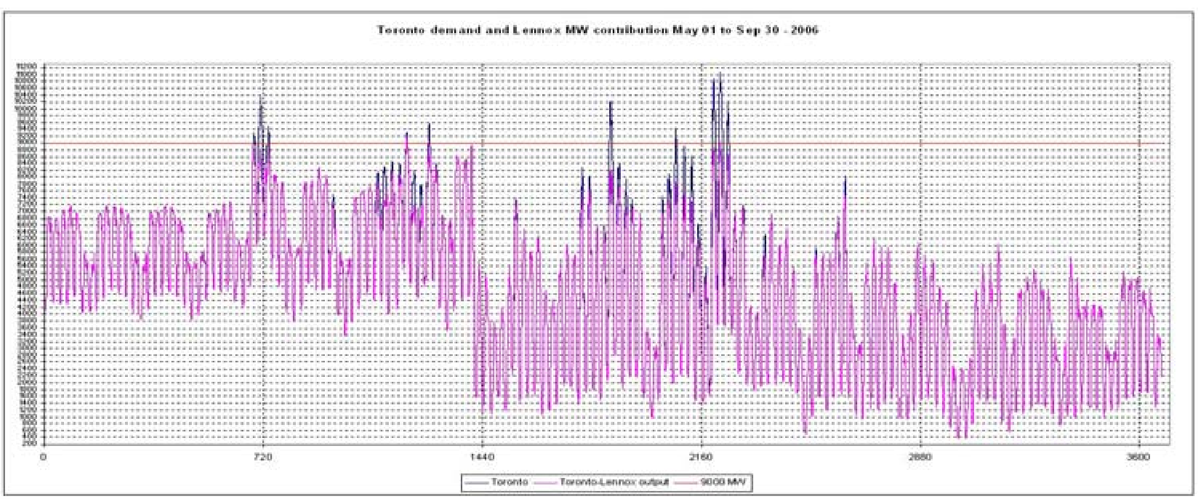

Figure 10: Lennox MW dependency on Toronto demand - summer 2006

Lennox support was constantly required during all those hours.

5.3 Dynamic Voltage Control for GTA

The summer high demand period also requires most of the reactive support that generation stations can provide. Analysis of summer 2005 data shows that Lennox support was required for a demand range in the Toronto zone starting at about 1500 MW and going up to the maximum. The capacity of all units was required when the demand went over 9000 MW:

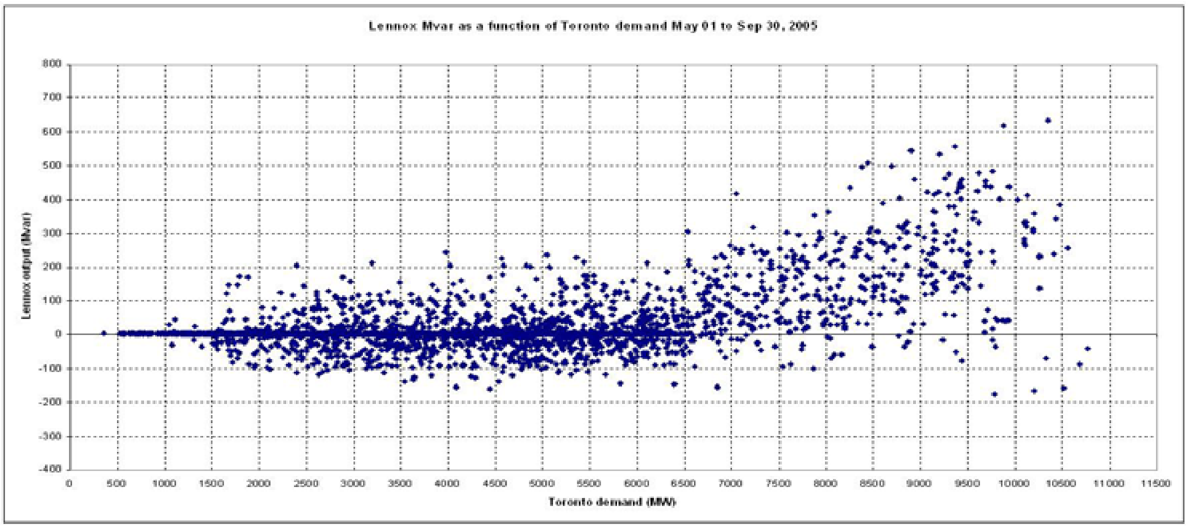

Figure 11: Lennox reactive output as a function of Toronto demand – summer 2005

During summer 2006 all four units were also required when Toronto zone demand exceeded 9000 MW:

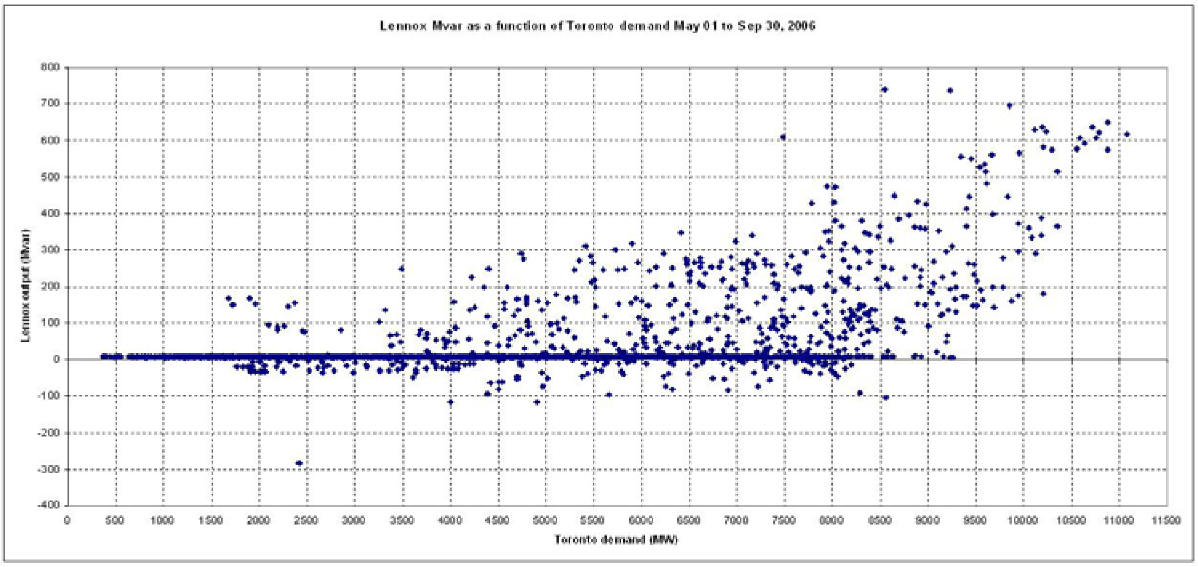

Figure 12: Lennox reactive output as a function of Toronto demand – summer 2006

It is to be noted that Pickering and Darlington reactive generation capabilities were also required when Toronto zone demand exceeded 9000 MW both in 2005 and 2006:

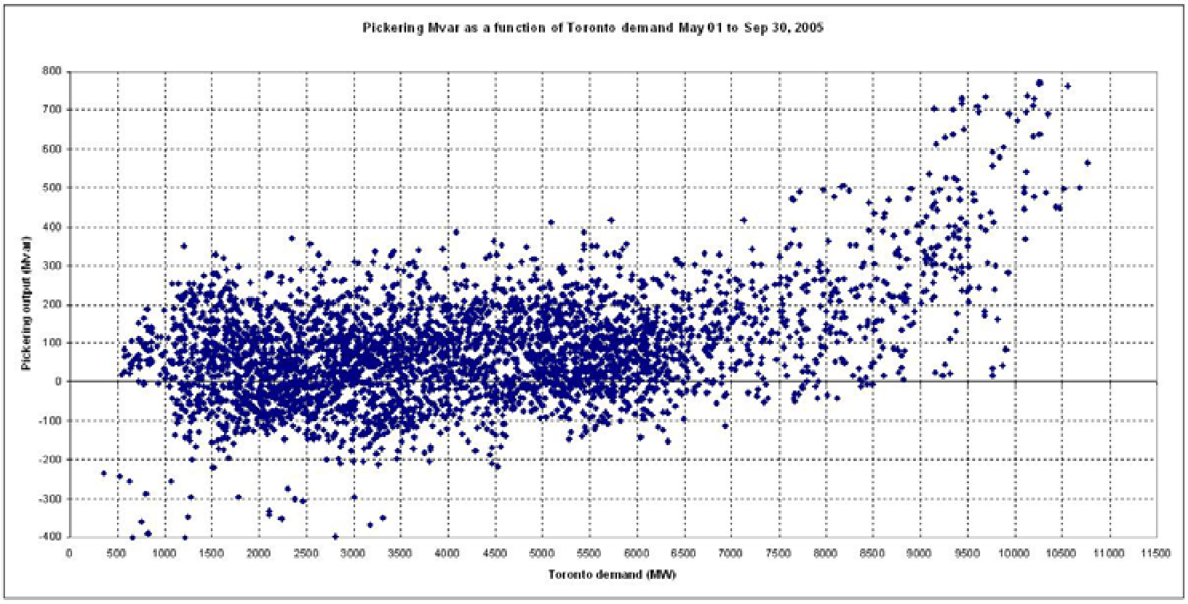

Figure 13: Pickering reactive output as a function of Toronto demand – summer 2005

The boundary at which Pickering changes from injecting and withdrawing reactive power to injecting only seems to be around a Toronto zone demand of 8500 MW. This boundary is better visible on summer 2006 data analysis:

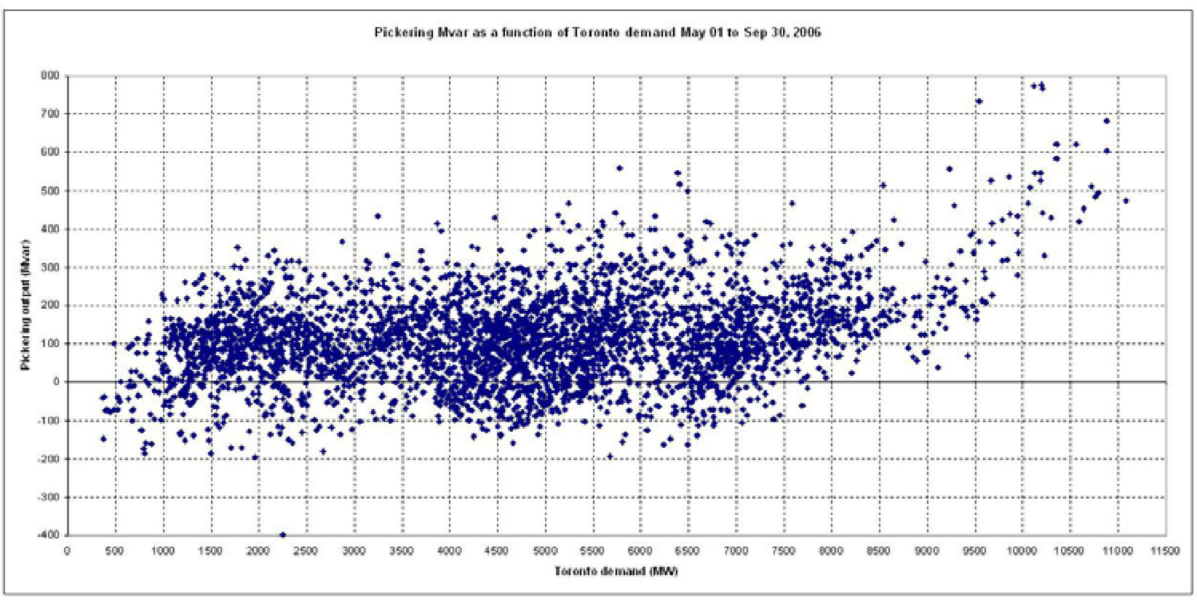

Figure 14: Pickering reactive output as a function of Toronto demand – summer 2006

Darlington shows a similar tendency of changing from bi-directional (injection/withdraw) to unidirectional (injection only) reactive support for Toronto zone demands in excess of 8500-9000 MW:

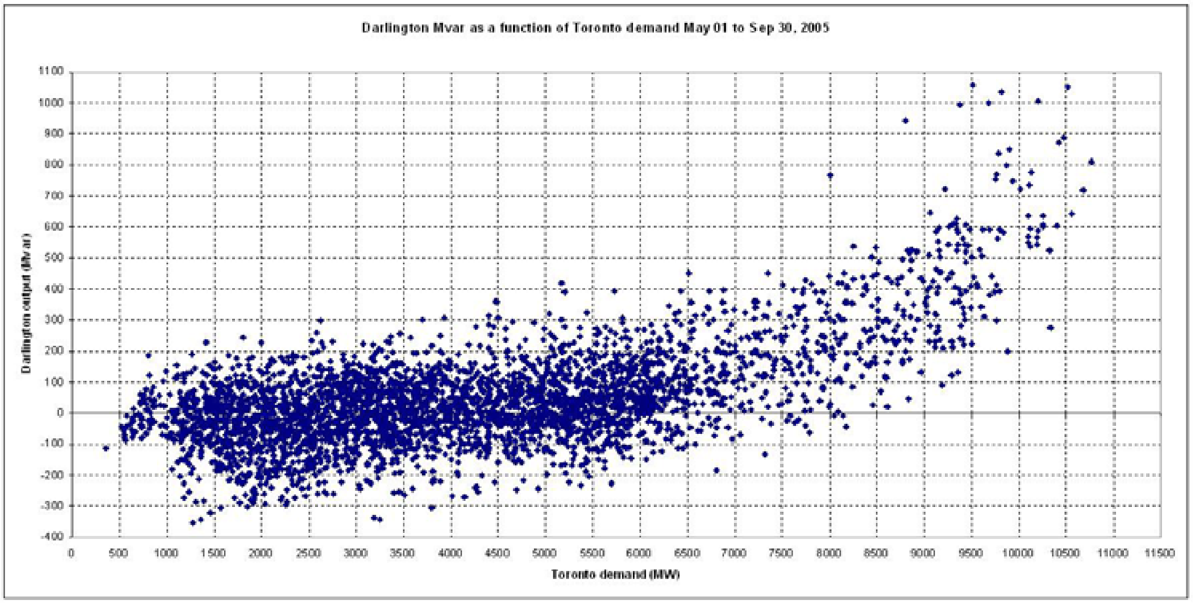

Figure 15: Darlington reactive output as a function of Toronto demand – summer 2005

Summer 2006 data analysis shows the same tendency:

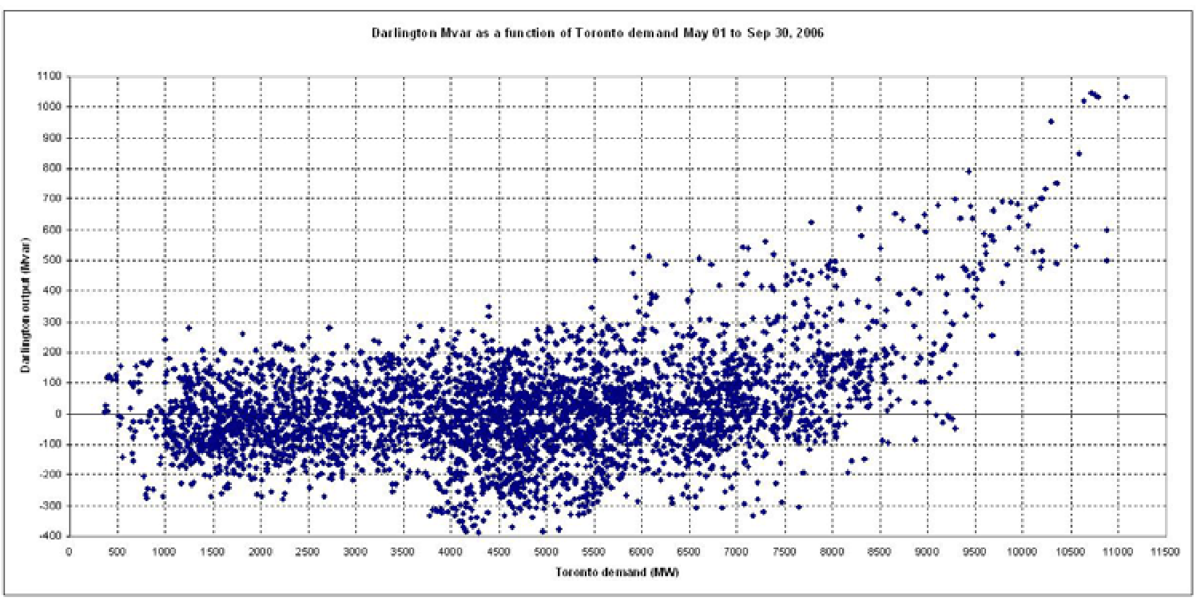

Figure 16: Darlington reactive output as a function of Toronto demand – summer 2006

For the Toronto zone demand higher than 9000 MW it appears that the system has fully used all other reactive resources and must rely on the main synchronous generators to keep the voltage within acceptable limits.

5.4 Reliable supply to Ottawa

Lennox units also assisted in maintaining a reliable supply to Ottawa. The generation is effective in controlling and maintaining voltage for the Ottawa area loads during periods of heavy demand.

As previously indicated, based on past experience, Ottawa is considered a winter peaking zone. Year 2006 brought a new and unique experience when Ottawa reached the highest demand in the summer mainly due to extreme weather conditions. The Flow into Ottawa (FIO) also reached its highest value during summer 2006:

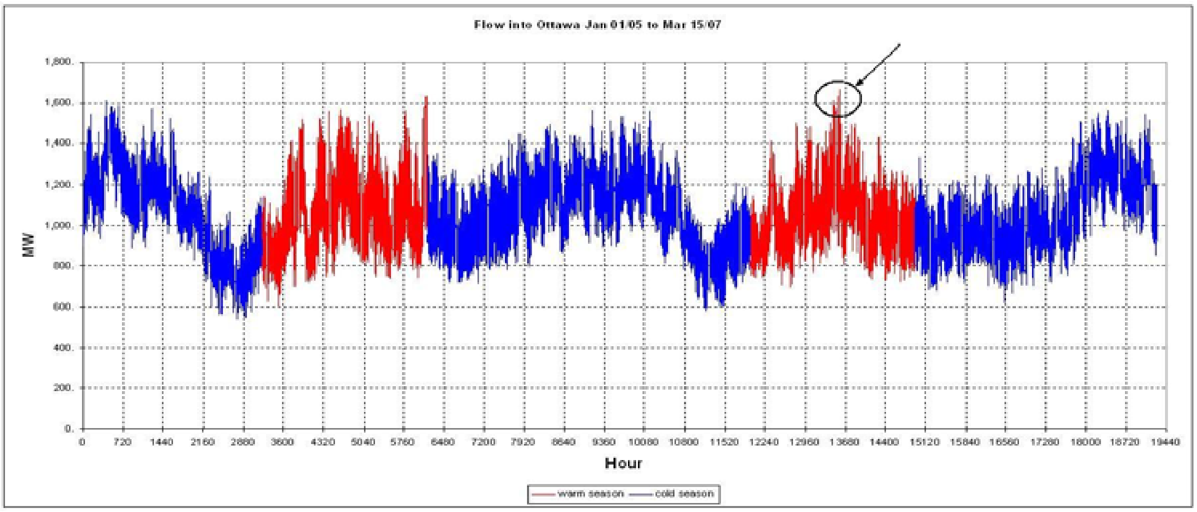

Figure 17: Flow into Ottawa (FIO) from Jan 01/05 to Mar 15/07

The highest FIO value in this period was recorded on July 20, 2006 at 14:00 – 1664 MW (90.99% of total zone demand for the Ottawa zone of 1829 MW). The highest demand for Ottawa zone was recorded on August 01, 2006 at 16:00 – 1930 MW while the corresponding FIO flows was 1495 MW, or 77.48% of the total zone demand.

Presently the FIO transfer limit depends on the number of Lennox units in service—each Lennox unit in service can improve, under certain conditions, the FIO transfer limit by 75 MW. Two units improve the FIO transfer limit by 150 MW. The third and fourth units are required to realize additional benefits of up to 150 MW when arming local load rejection.

The generation at Barrett Chute, Stewartville and Chats Falls 115 kV are injecting in Ottawa zone through what is knows as “Flow into Ottawa 115 kV” (FIO-115 kV) but “behind” the FIO, their combined generation contributing to FIO reduction.

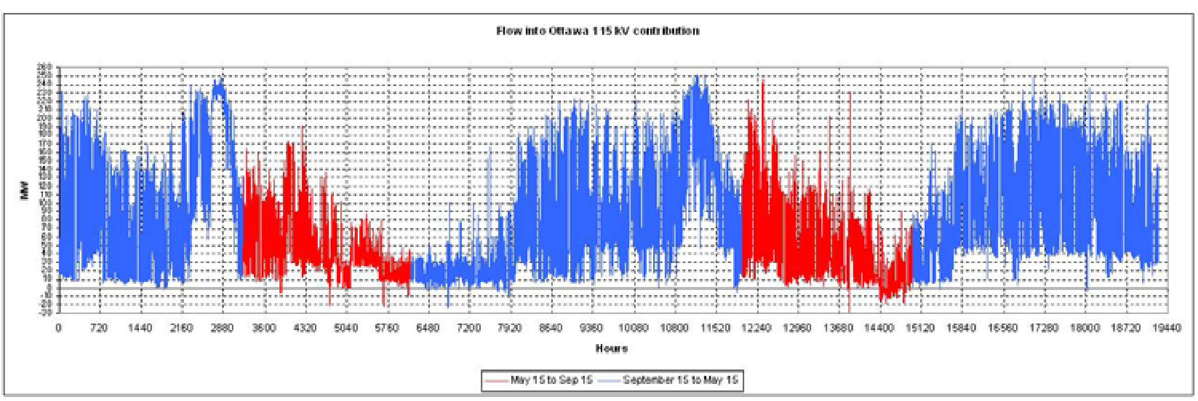

Figure 18: Flow into Ottawa 115 kV (FIO 115 -kV) from Jan 01/05 to Mar 15/07

One quick observation from the plot above is that FIO-115 kV transfer has a more consistent contribution during the cold season than the warm season. It should also be noted that as the summer advances the FIO-115 kV average contribution reduces, mainly due to lower water levels.

To better understand the contribution of FIO-115 kV this overall profile was first split into two: from May 15 to Sep 15, 2005 and 2006 respectively (shown as "May 15 to Sep 15") and from Jan 01, 2005 to May 15, 2005, from Sep 15, 2005 to May 15, 2006 and from Sep 15, 2006 to Mar 15, 2007 (shown as "Sep 15 to May 15"):

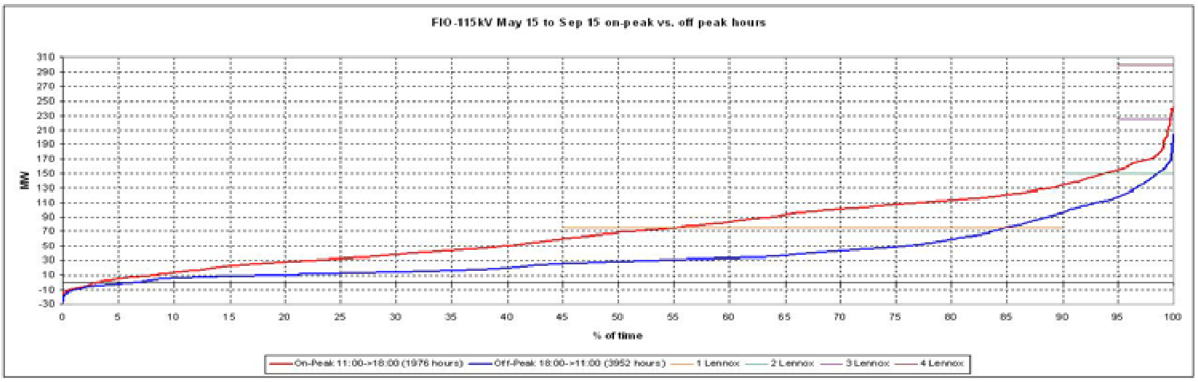

Figure 19: FIO-115kV on-peak vs. off-peak from May 15 to Sep 15

From May 15 to Sep 15 the FIO-115kV contribution at peak hours (11:00 to 18:00) was less than the equivalent FIO improvement of one Lennox unit for about 55% of the time and less than two Lennox units for 95% of the time. It only exceeded the equivalent of three Lennox units for 5 hours. During off-peak hours (18:00 to 11:00 next day) the contribution was even lower.

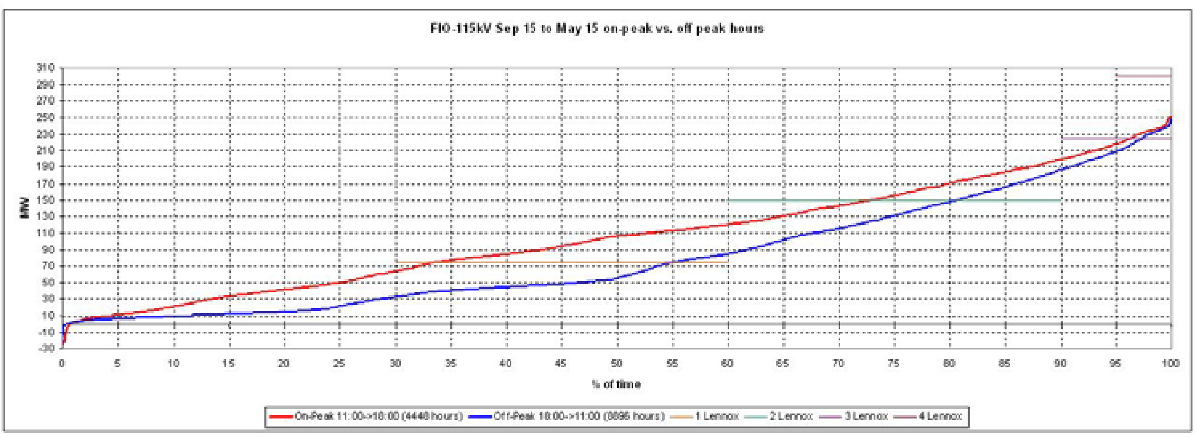

Figure 20: FIO-115kV on-peak vs. off-peak from Sep 15 to May 15 (following year)

During the remaining hours ("Sep 15 to May 15") the FIO-115kV contribution was a little more consistent but only exceeded the equivalent of three Lennox units for 165 on-peak hours and 233 off-peak hours. It never reached the equivalent of all four Lennox units and for more than 95% of the time it was below the equivalent of three Lennox units.

Another injection in Ottawa zone that can reduce the FIO transfer is the generator at Ontario Health Science Center (OHSC). The maximum output of this generator is almost 73 MW, or approximately the equivalent improvement to the transfer limit of one Lennox unit:

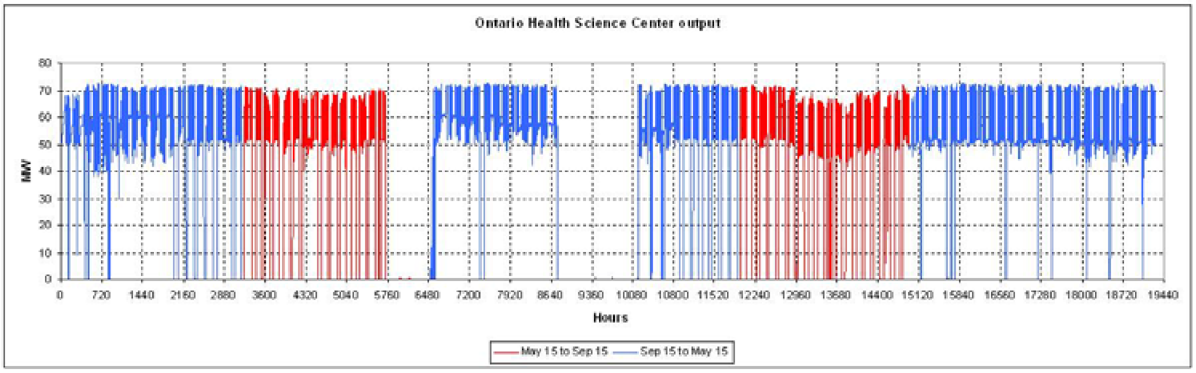

Figure 21: Ontario Health Science Center (OHSC) from Jan 01/05 to Mar 15/07

Analysis of OHSC data indicates that:

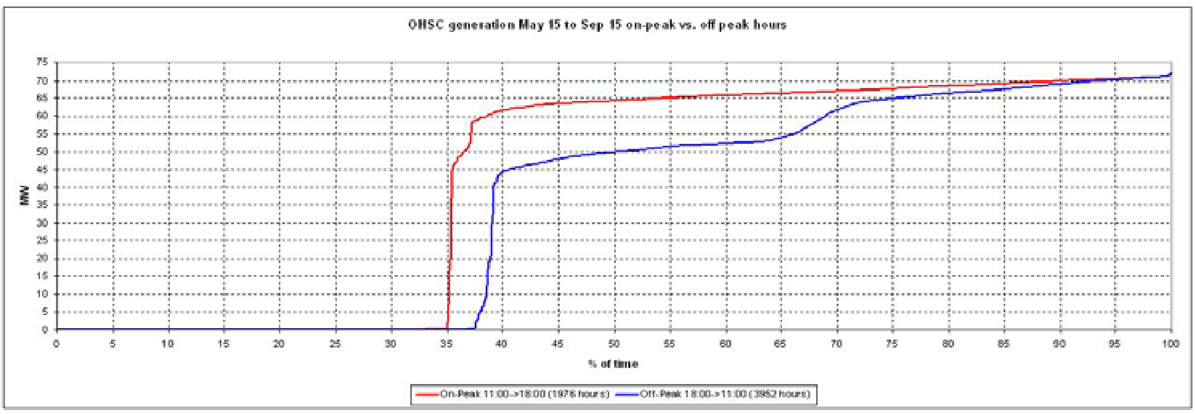

Figure 22: OHSC on-peak vs. off-peak from May 15 to Sep 15

OHSC generation was unavailable during the summer, from 11:00 to 18:00 for 35% of the time and from 18:00 to 11:00 next day for 37% of the time.

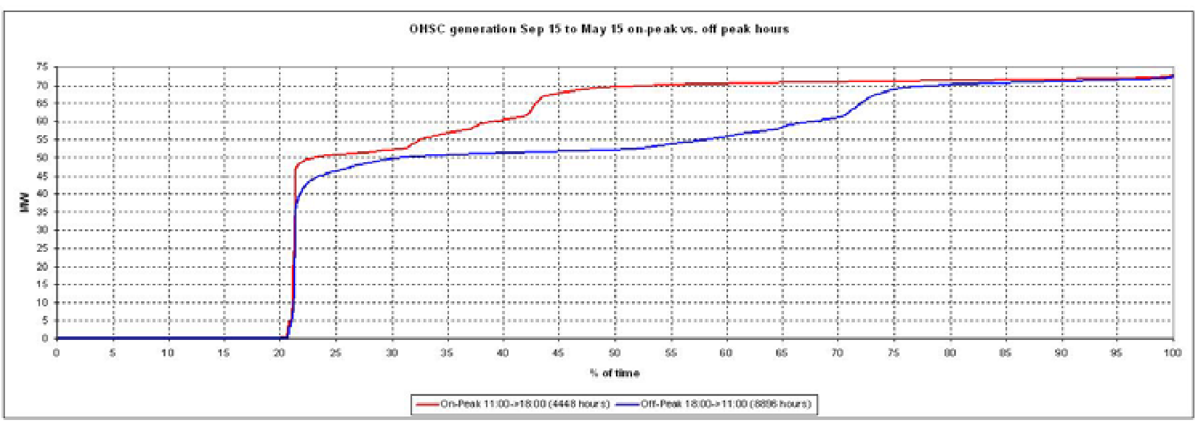

Figure 23: OHSC on-peak vs. off-peak from Sep 15 to May 15 (next year)

During the cold season, OHSC generation shows a higher availability being only 21-22% of time unavailable. Unavailability of OHSC (self scheduler), under certain conditions, must be replaced by Lennox generation (or imports).

The third and last injection into Ottawa zone that can reduce the FIO transfer is the Hydro Quebec connection at Masson: 115kV H9A and 230kV D5A:

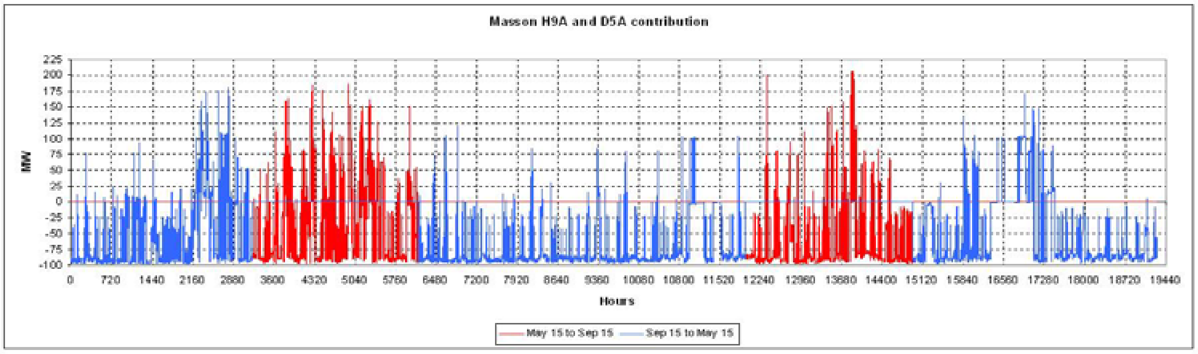

Figure 24: Masson H9A and D5A (Masson) from Jan 01/05 to Mar 15/07

The majority of time the Masson flow is from Ontario to Quebec (negative on the graph) which represents an additional burden for the FIO interface.

Figure 25: Masson on-peak vs. off-peak from May 15 to Sep 15

Detailed analysis of Masson lines data shows that imports from Quebec were flowing for about 35% of the time from 11:00 to 18:00 and 15% of the time from 18:00 to 11:00 next day, for the periods May 15 to Sep 15.

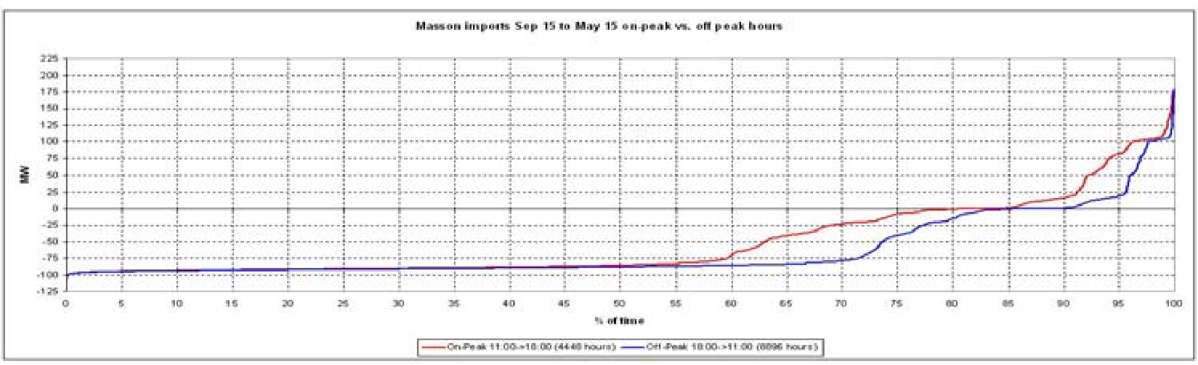

Figure 26: Masson on-peak vs. off-peak from Sep 15 to May 15 (next year)

During the fall, winter and early spring Masson was predominantly export, so the contribution to FIO transfer reduction only happened for 15% of the time during on-peak hours and 10% of time for off-peak hours.

To better understand how much we can count on these three components for reliability purposes we should have a look at their combined contribution:

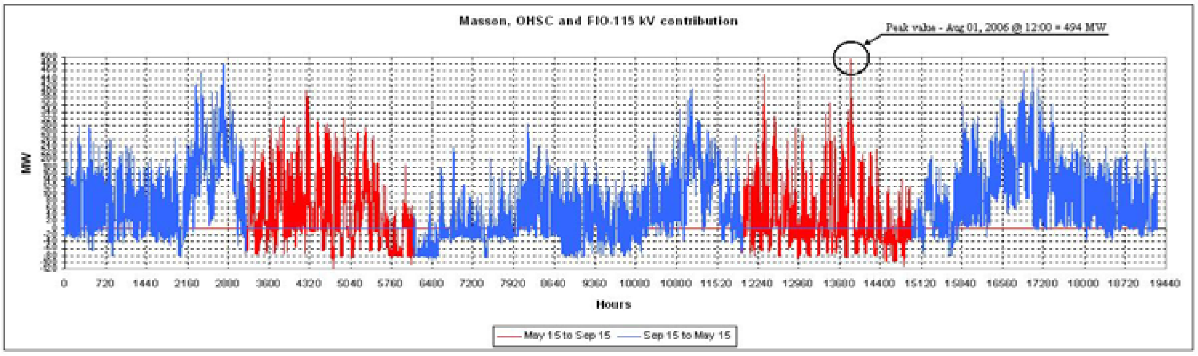

Figure 27: Masson, OHSC & FIO-115kV from Jan 01/05 to Mar 15/07

Their highest contribution (494 MW) from these three components over the study period was achieved on Aug 01, 2006 at 12:00.

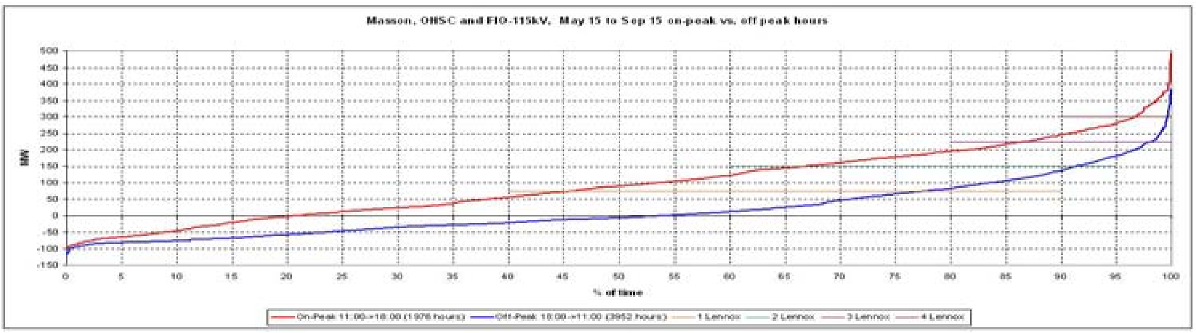

Figure 28: Masson, OHSC & FIO-115kV on-peak vs. off-peak from May 15 to Sep 15

For the warm season peak (May 15 to Sep 15 and from hour 11:00 to 18:00) this contribution was less then the equivalent of one Lennox unit for about 45% of the time, less then two Lennox units for 65% of the time, three units for 85% of the time and four units for about 97% of the time. The combined contribution of Masson imports, OHSC generation and FIO-115 kV was above the equivalent of four Lennox units for 3% of the mid-day hours during the warm season.

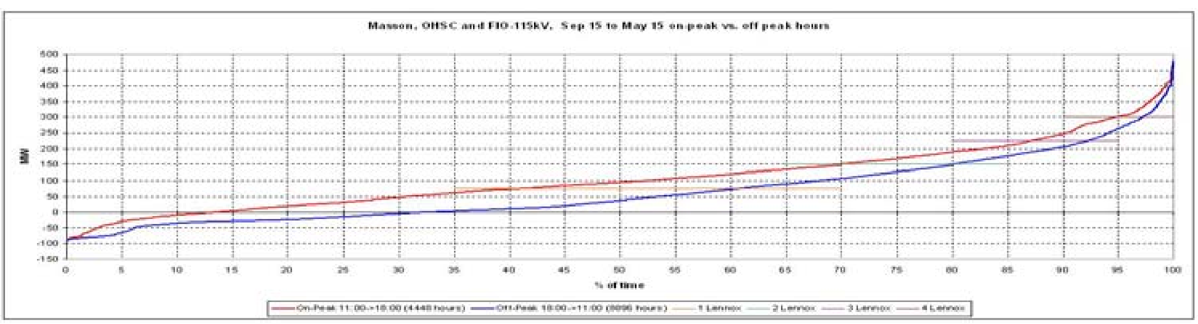

Figure 29: Masson, OHSC & FIO-115kV on-peak vs. off-peak from Sep 15 to May 15 (+1Y)

Taking into consideration that Ottawa is – based on historical readings – considered a winter peaking zone it should be noted that 40% of the time the combined contribution of Masson imports, OHSC generation and FIO-115 kV was less than the equivalent of one Lennox unit, 70% less than two, 87% less than three and 95% less than four. It appears that the overall contribution of these components is better during the cold than the warm season.

On top of the above contribution the FIO required Lennox support for up to four units for 84 hours:

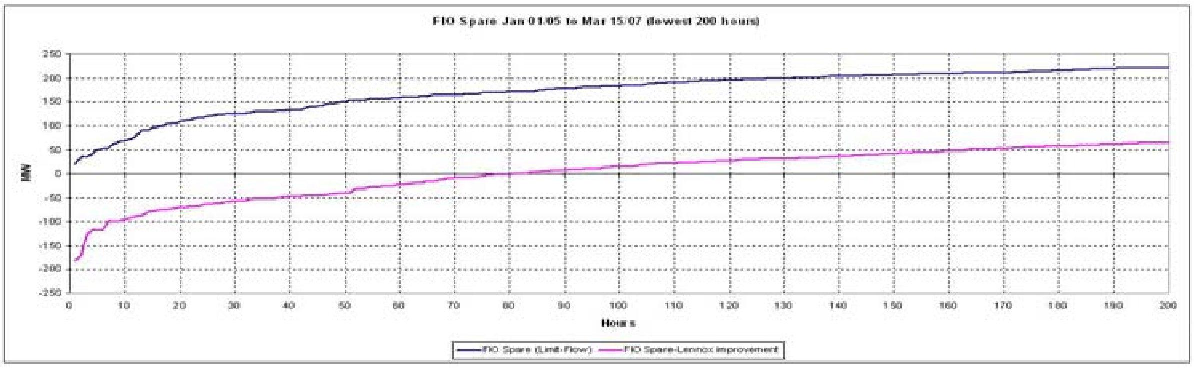

Figure 30: FIO spare from Jan 01/05 to Mar 15/07

The graph shows that without the Lennox improvement the FIO transfer limit would've been exceeded for up to 84 hours. A detailed analysis of these 84 hours indicates that with few exceptions, three or four Lennox units were used to increase the transfer limit during weekdays and daytime:

Table 3: FIO spare supported by Lennox units

Date	Season	Day of week	Hours	From	To	Lennox Units	FIO-115 (average MW)	% of max FIO-115	OHSC (MW)	Masson (MW) - minus = export	FIO-115kV +OHSC +Masson	% of Max	FIO (average MW)	% of max FIO
2005/06/11	W	Sat	4	13	17	3	63	25%	0	76	139	28%	1451	87%
2005/06/13	W	Mon	6	14	19	4	56	22%	66	15	136	28%	1443	87%
2005/06/14	W	Tue	1	16	16	4	141	56%	65	-38	168	34%	1495	90%
2005/06/25	W	Sat	2	11	12	4	116	46%	0	-13	103	21%	1409	85%
2005/07/11	W	Mon	8	11	18	4	83	33%	64	99	247	50%	1508	91%
2005/07/12	W	Tue	7	11	17	4	80	32%	65	107	252	51%	1507	91%
2005/07/14	W	Thu	2	14	15	4	70	28%	65	69	204	41%	1442	87%
2005/07/18	W	Mon	8	12	20	4	81	32%	64	63	208	42%	1489	89%
2005/07/19	W	Tue	5	13	17	4	80	32%	65	46	190	39%	1485	89%
2005/07/21	W	Thu	1	15	15	4	98	39%	65	58	221	45%	1453	87%
2005/07/25	W	Mon	3	11	16	4	26	10%	64	130	220	45%	1443	87%
2005/08/02	W	Tue	1	17	17	4	77	31%	64	0	141	29%	1536	92%
2005/08/05	W	Fri	3	10	12	4	48	19%	65	-90	23	5%	1497	90%
2005/08/08	W	Mon	2	16	17	4	73	29%	65	62	200	40%	1456	87%
2005/09/12	W	Mon	1	16	16	3	34	14%	0	3	37	7%	1525	92%
2005/09/13	W	Tue	4	12	17	3	16	6%	0	12	28	6%	1556	93%
2005/09/14	W	Wed	3	13	17	3	34	14%	0	-40	-5	-1%	1573	95%
2005/11/15	C	Tue	4	16	19	2	38	15%	72	-89	21	4%	1319	79%
2005/12/02	C	Fri	1	17	17	1	171	68%	71	-87	156	32%	1296	78%
2006/07/17	W	Mon	4	14	21	4	101	40%	61	95	258	52%	1501	90%
2006/07/19	W	Wed	6	13	18	2	45	18%	0	-92	-47	-9%	1552	93%
2006/07/31	W	Mon	1	17	17	4	81	32%	61	0	141	29%	1477	89%
2006/08/01	W	Tue	7	11	18	4	127	51%	53	190	370	75%	1441	87%
Total/Max	W=79		84	10	21		251	6%			494	-9%	1664	78%
	C=5							68%				75%		95%

Lennox support was required for 79 hours during the warm seasons, with few exceptions all of them were on-peak hours. This represents 4% of the time, 1% more than the combined Masson imports, OHSC generation and FIO-115 kV could contribute for the equivalent of four and over four Lennox units. Despite the mild weather during the cold season, Lennox units were required for 5 hours to increase the FIO transfer limit. The table shows that consistently Lennox units were required to support high FIO transfers (between 70% and 95% of the maximum of 1664 MW) while FIO-115 kV was quite low (between 6% and 68% of the maximum of 251 MW), OHSC was not generating and the exchange at Masson was low or going out of Ontario. The overall contribution of these three elements was between -9% (due to the export) and 75%, of a maximum of 494 MW. Without Lennox support up to more than 175 MW (at maximum) of load reduction would've been required in Ottawa zone.

– End of Section –

6. Analysis of 2008 forecast

To identify the future need for Lennox TGS during the period October 2007 to September 2008, this section reviewed the most significant factors affecting the reliability need for Lennox to:

- Accommodate expected peak flows to the Ottawa area (Reliable Supply to Ottawa),
- Accommodate expected peak flows towards Toronto from the west over the FETT (Flow East To Toronto) and FIB (Flow Into Burlington) transmission paths,
- Provide sufficient reactive resources and adequately control voltages in the Greater Toronto area, and eastern Ontario including the Ottawa area,

These factors are:

- Extreme weather peak demand forecast for the study period,
- Hydro-electric capacity and energy availability for the study period,
- Availability of major generators east of Toronto, including Pickering, Darlington, and Lennox.
- Affect of imports into Ontario.

Some of these elements were mostly covered in Part 5 – Operational data analysis and the previous Lennox TGS deregistration analysis for the period October 2006 to September 2007. The analysis of 2008 forecast focused on changes that are expected to happen over the current study period.

6.1 Capacity to Control flows from the west on FETT (Flow East To Toronto) and FIB (Flow Into Burlington), and Dynamic Voltage Control for GTA

The previous Lennox GS deregistration analysis (October 2006 to September 2007), indicated that at least three Lennox units were required to reduce the congestion over the transmission interfaces located west of the GTA and ensure reliable supply for Toronto area.

A comparison of the major factors in the previous and present report reveals:

The latest forecast for 2008 indicates an extreme weather demand of 10672 MW, which represents an increase of 357 MW above the demand forecast of 10315 MW used in the previous Lennox analysis. The total Ontario forecast demand for 2008 is forecast to go as high as 27824 MW under extreme weather conditions, which represents an 88 MW increase over the 2007 forecast (27736 MW).

There are no transmission reinforcements scheduled for the FETT or FIB transmission paths over the study period so the increase in forecast demand in the Toronto area will increase the requirements for MW flow into the area, and increase the need for voltage control in the area; both factors will require increased reliance on Lennox.

To determine the effect of hydro-electric generation capacity and energy availability, the Flow South (FS) analysis was expanded to include data from January 01, 2005 to March 15, 2007:

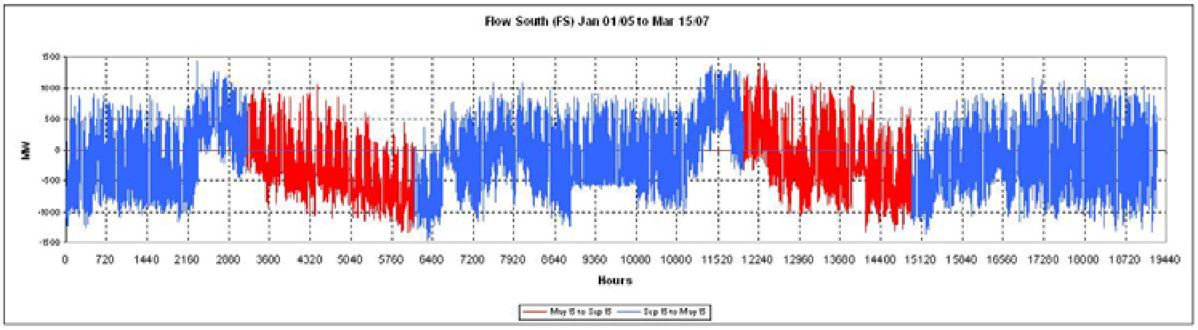

Figure 31: Flow South (FS) from Jan 01, 05 to Mar 15, 07

The graph shows that FS maximums have a tendency to decrease during the summer, mainly due to a reduction of water levels.

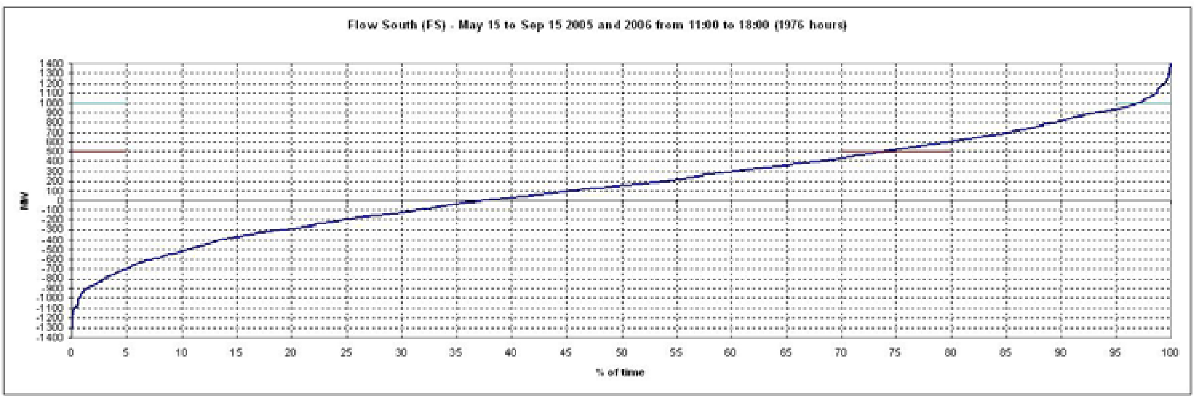

Figure 32: Flow South (FS) from May 15 to Sep 15, hours 11:00 to 18:00

The above figure shows that from May 15 to Sep 15 of 2005 and 2006 FS, from hour 11:00 to 18:00 the Flow South was below 500 MW 75% of the time. It exceeded 1000 MW for about 3% of the time and was between 500 MW and 1000 MW for 22% of the time. Knowing that periods of high demand are usually in July and Aug, and taking into consideration the reduction in water levels, it would be realistic to assume a reliable Flow South value for this de-registration analysis between 500 MW to 600 MW. The previous study has assumed a Flow South value of 1000 MW, which appears to be overly optimistic. Therefore, this reduced hydro-electric availability is also contributing to an increased need for Lennox in the study period.

The large generating unit's availability, shown on Table 1 and Figure 2, indicates that there is a high likelihood of having one unit at Pickering out of service. The previous study assumed all Pickering units in service and assessed the impact of losing one or two units.

The new generation east of FETT scheduled to go in service before the end of the current study period is represented by:

- Goreway Phase I – 485 MW, proposed in service June 2007
- Portlands Energy Center Phase I – 280 MW, proposed in service September 2008

This study mainly looks at summer 2008, from this perspective Portlands will become operational too late to make a difference.

The previous report recommended that the fourth unit at Lennox be contracted to account for delays in bringing Goreway Phase I on line. For summer 2008, due to the expected demand growth, Goreway Phase I is not providing sufficient output to replace one Lennox unit, as from the total 485 MW, 357 MW will only offset the demand growth in the Toronto zone.

Therefore all of the major factors affecting this analysis are expected to result in an increased need for Lennox.

6.2 Reliable supply to Ottawa

Simulations were performed using a typical summer and winter demand pattern for Ottawa, in an attempt to determine Lennox retirement impact.

August 01, 2006 is a good example of peak summer day with extreme weather. 2008 forecast indicates just a very small change in demand of 0.5% (1.00523) compared to 2006.

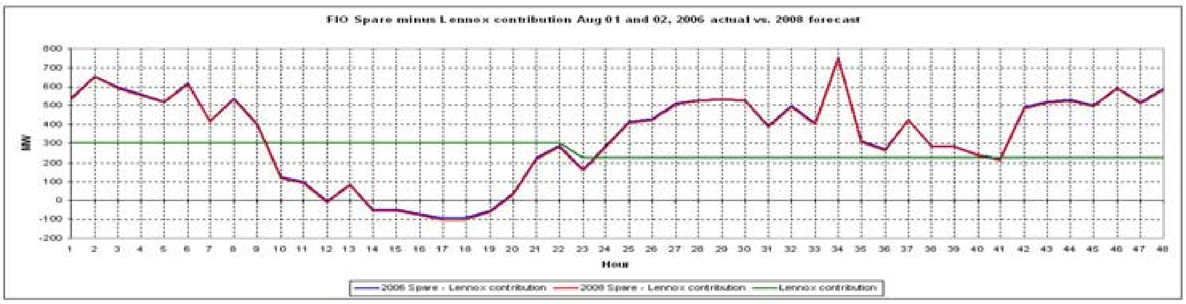

Figure 33: FIO spare minus Lennox contribution 2006 actual and 2008 forecast

Because of the small difference the two profiles are very close to each other. Lennox contribution during Aug 01 and 02, 2006 is also represented. On Aug 01 all 4 Lennox units were in service increasing the FIO limit by 300 MW. The graph shows that without Lennox support the limit would've been exceeded for almost six hours. During this time, the highest violation would've been as high as 100 MW which represents more than the equivalent contribution of one Lennox unit. Assuming the same pattern for summer 2008, without support provided by all four Lennox units during a similar period of time (at least six hours) about 100 MW of load must be curtailed in order to operate reliably.

For the winter season, the lowest temperature in Ottawa was reached on February 05, 2007.

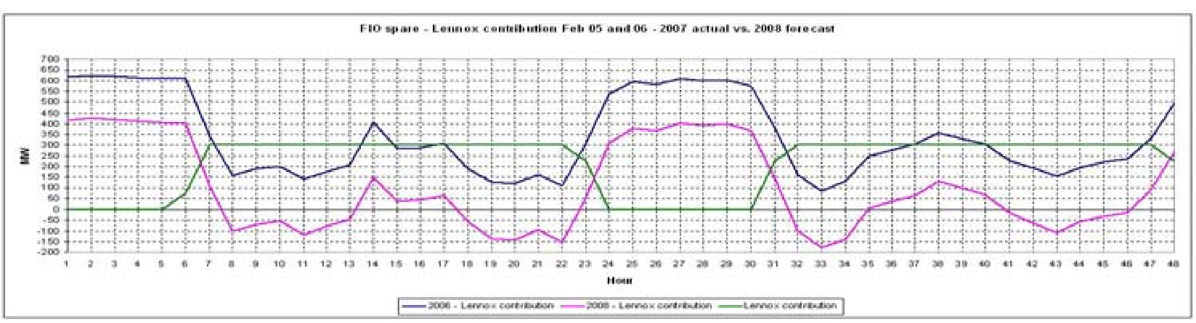

Figure 34: FIO spare minus Lennox contribution 2006 actual and 2008 forecast

As previously indicated, the recorded February 05, 2007 temperature ranked number 46 out of 1073 measurements taken from 1970 to 2007. This indicates that the expected extreme-weather temperature would be even lower. For this reason, the multiplication factor that accounts for extreme weather forecast for 2008 is 1.1717. For this calculation the highest demand recorded on February 05, 2007 – 1821 MW – was compared against the forecast for February 2008 – 2134 MW. Lennox contribution was also included to indicate that up to four units were used in 2006 to increase the transfer limits. The graph shows that in 2008 the support of at least three units (over almost 200 MW which is the equivalent of 3 Lennox units) may be required to support the winter peak transfers under extreme weather conditions. Without this support, over a period of two days, load interrupting measures may be required for about 19 hours. Over the study period, the demand in Ottawa, under extreme weather conditions, is expected to go as high as 2201 MW (forecast for December 2007 – see Appendix A). Recognizing that the use of post-contingency load rejection can be used to expand the transfer limits only when three or more Lennox units are in service, de-registering one Lennox unit would not allow for any contingencies or unavailability of the remaining Lennox units.

To better understand the impact of taking Lennox units out of service, a set of simulations were performed assuming that each Lennox unit is replaced by the new gas fired generation in GTA (Goreway and Portlands). The P-V curves were generated with all elements in service, using a constant MVA model pre and post-contingency, monitoring the Hawthorne 115 kV bus for the most severe contingency that can affect Ottawa: loss of one 500 kV circuit from Lennox to Hawthorne.

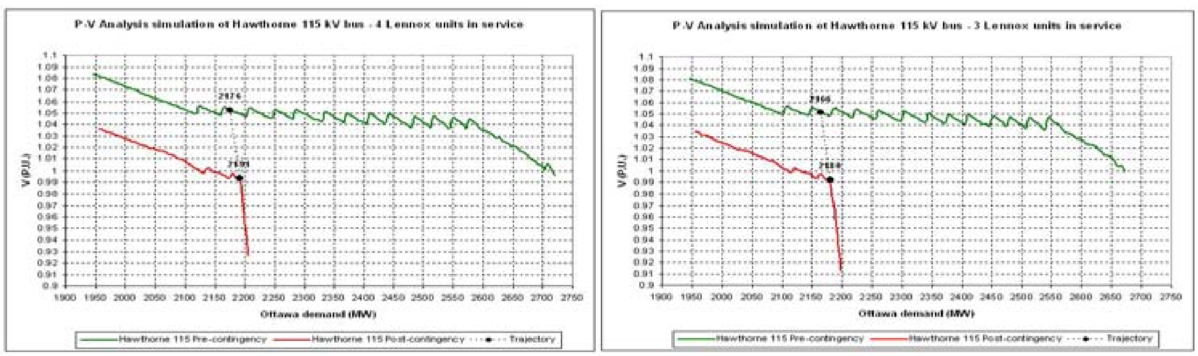

Figure 35: One unit reduction at Lennox

The P-V curves show that by reducing one Lennox unit the maximum pre-contingency demand that can be reliably supplied in Ottawa decreases by 10 MW, from 2176 MW to 2166 MW (the post contingency transfer is slightly higher because the transmission losses are increasing after the loss of one 500 kV circuit).

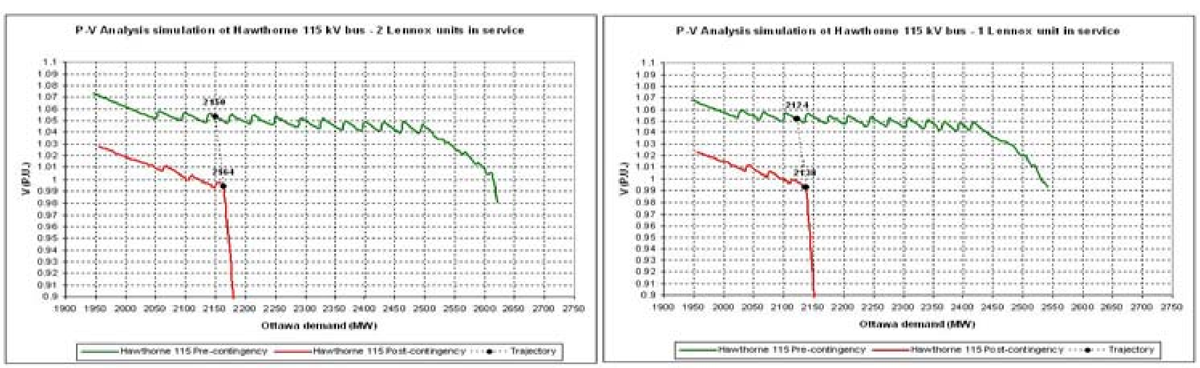

Figure 36: Two and three units reduction at Lennox

By further reducing the number of units in service the demand supply capability decreases by 16 MW (from 2166 MW to 2150 MW) and respectively by 26 MW (from 2150 MW to 2124 MW).

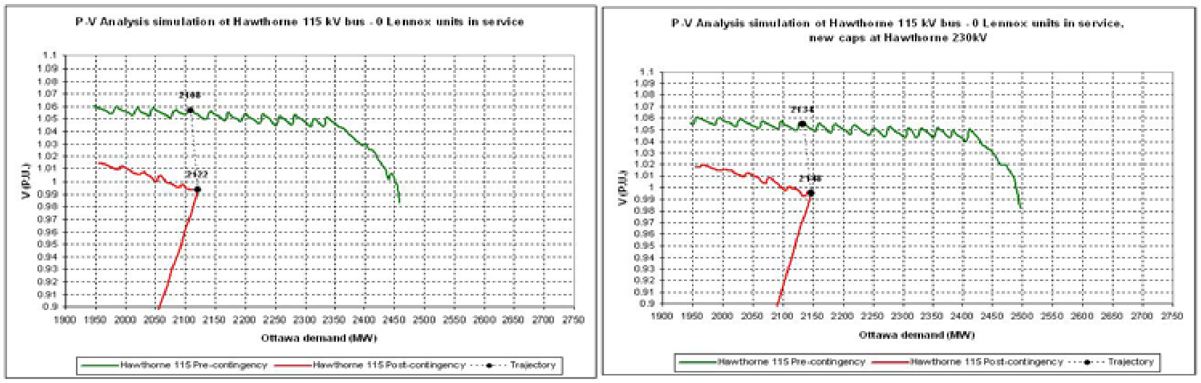

Figure 37: Zero units at Lennox with and without the proposed 230kV caps at Hawthorne

If the last Lennox unit is taken out of service the transfer capability decreases to 2108 MW (by another 16 MW) which represents a total decrease by 68 MW. The last simulation was performed to assess the effect of the new 230 kV shunt capacitors that are proposed as part of the HVDC connection with Hydro Quebec (these are planned to be in service beyond the study period). It shows that under the simulated conditions the contribution of the two 200 Mvar at 249.4 kV capacitors can only provide the equivalent improvement of a little more than one Lennox unit (26 MW – from 2108 MW to 2134 MW). It should be noted that all numbers presented are approximate because the simulation was performed by proportionally increasing the demand in Ottawa in steps of 5 MW, using constant power factor.

To simplify this simulation, the power factor was monitored for the flow through the 230/115 kV autotransformers in Hawthorne. It doesn't provide detailed indication of the power factor of each load or the status of the reactive compensation in Ottawa but the high level information is sufficient for this analysis.

It was determined that from January 01, 2005 to March 15, 2007 this power factor was between unity (very close to) to as low as 0.9, with an average of 0.99.

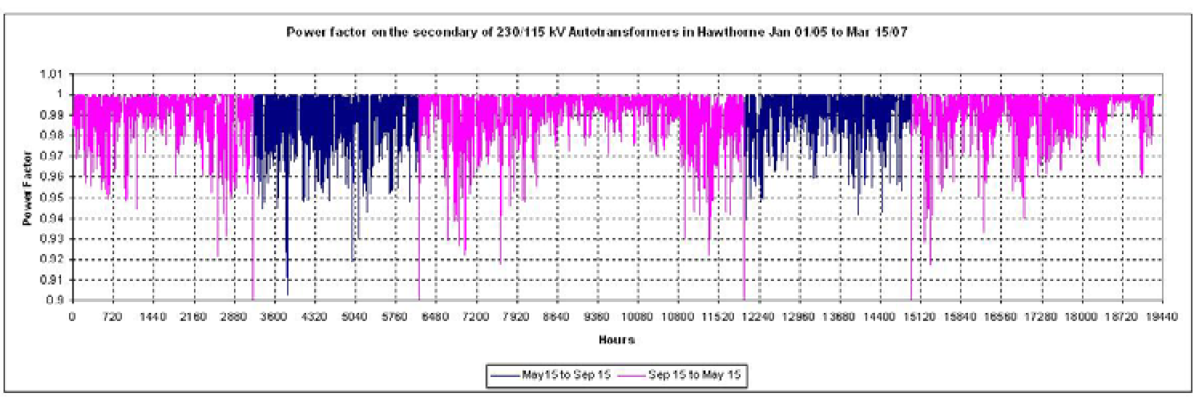

Figure 38: Hawthorne autotransformers power factor - Jan 01/05 to Mar 15/07

For these simulations an average power factor of 0.99 was selected:

Table 4: Simulated Power factor measured at Hawthorne autotransformers

Bus from	Bus to	circuit	P	Q	P.F.
HAWTHORN220	HAWTHORN118	T4	153	-21	0.99
HAWTHORN220	HAWTHORN118	T5	159	-23	0.99
HAWTHORN220	HAWTHORN118	T6	163	-24	0.99
HAWTHORN220	HAWTHORN118	T9	155	-22	0.99
Total			630	-89	0.99

Figure 38 shows that during the cold season when the demand forecast is higher the average power factor is higher also which would allow for higher transfer limits.

The IESO planning criteria requires that the maximum acceptable pre-contingency power transfer must be lesser of:

- A pre-contingency power transfer that is 10% lower than the voltage instability point of the pre-contingency curve and
- A pre-contingency transfer that results in a post-contingency power flow that is 5% lower than the voltage instability point of the post-contingency curve.

Over the study period the highest summer demand is expected in August 2008 – 1969 MW and the highest winter demand in December 2007 – 2201 MW. The following table shows how the planning criterion applies to these summer and winter peak demand values.

Table 5: IESO planning criteria for Ottawa demand

	Pre-contingency critical point	Pre-contingency 10% criteria			Post-contingency critical point	Post-contingency 5% criteria		
Lennox units		Maximum acceptable	Summer reserve	Winter reserve		Maximum acceptable	Summer reserve	Winter reserve
#	MW	MW	MW	MW	MW	MW	MW	MW
4	2720	2448	480	247	2191	2081	113	-120
3	2672	2405	437	204	2180	2071	103	-130
2	2620	2358	390	157	2164	2056	88	-145
1	2542	2288	320	87	2138	2031	63	-170
0	2457	2211	243	10	2122	2016	48	-185
0+caps[4]	2495	2246	278	45	2148	2041	73	-160

Table 5 shows that the pre-contingency criterion is met in all cases. Lennox total pre-contingency contribution (4 units – 0 units) is 237 MW. With no Lennox units in service the winter reserve drops to only 10 MW, representing 0.4% of the forecast Ottawa peak demand.

The 5% post-contingency criteria shows that the extreme-weather demand exceeds the available transfer capability even with all Lennox units in service, and will require post-contingency load rejection to control post-contingency voltages. This confirms the current transfer limit structure that requires a combination of Lennox units and post-contingency load rejection to ensure reliable supply to Ottawa.

– End of Section –

[4] Results of the simulation performed for assessing the contribution of the new 230 kV capacitors proposed for installation at Hawthorne as part of the new HVDC connection to Hydro Quebec.

Appendix A: 2008 forecast

Table 6: Zonal demand forecast from January 2007 to December 2008

Date	Bruce	East	Essa	Niagara	NorthEast	NorthWest	Ontario	Ottawa	SouthWest	Toronto	West
Jan-07	98	1,933	1,651	844	1,829	882	25,391	2,147	5,024	8,407	2,575
Feb-07	95	1,894	1,630	814	1,762	841	24,891	2,108	4,957	8,289	2,500
Mar-07	88	1,742	1,513	778	1,749	860	23,860	1,955	4,742	7,977	2,456
Apr-07	55	1,357	1,219	788	1,319	710	21,993	1,612	4,315	8,112	2,507
May-07	54	1,424	1,293	856	1,296	697	23,531	1,667	4,626	8,883	2,734
Jun-07	64	1,586	1,467	1,021	1,343	769	26,730	1,935	5,220	10,063	3,261
Jul-07	60	1,610	1,522	1,069	1,327	743	27,575	1,923	5,370	10,572	3,377
Aug-07	64	1,611	1,539	1,064	1,407	757	27,492	1,952	5,291	10,440	3,367
Sep-07	64	1,515	1,367	988	1,416	727	25,850	1,906	5,082	9,678	3,107
Oct-07	60	1,362	1,187	871	1,404	714	23,909	1,711	4,703	9,124	2,774
Nov-07	92	1,776	1,534	811	1,704	832	24,178	2,005	4,885	8,046	2,493
Dec-07	97	1,932	1,674	850	1,835	868	25,525	2,201	5,041	8,400	2,627
Jan-08	101	1,948	1,693	838	1,827	871	25,576	2,173	5,086	8,451	2,587
Feb-08	98	1,909	1,673	808	1,762	829	25,075	2,134	5,019	8,334	2,509
Mar-08	91	1,763	1,566	776	1,695	844	24,072	1,998	4,806	8,055	2,477
Apr-08	57	1,373	1,263	787	1,332	699	22,246	1,629	4,378	8,205	2,523
May-08	56	1,439	1,337	855	1,305	692	23,784	1,683	4,689	8,976	2,751
Jun-08	66	1,601	1,513	1,020	1,351	762	26,980	1,951	5,283	10,156	3,277
Jul-08	62	1,625	1,566	1,067	1,328	737	27,824	1,940	5,436	10,672	3,390
Aug-08	65	1,625	1,581	1,070	1,421	747	27,737	1,968	5,345	10,524	3,392
Sep-08	66	1,531	1,415	986	1,428	720	26,097	1,919	5,144	9,765	3,124
Oct-08	62	1,371	1,226	867	1,412	703	24,117	1,726	4,758	9,204	2,786
Nov-08	95	1,784	1,569	803	1,709	820	24,329	2,028	4,941	8,079	2,502
Dec-08	98	1,837	1,613	834	1,755	852	25,087	2,072	5,056	8,382	2,587
Highest ->	101	1,948	1,693	1,070	1,835	882	27,824	2,201	5,436	10,672	3,392

– End of Section –

Appendix B: PSS/E model used for simulations.

Only the scenarios including 4 Lennox units and 0 Lennox units were included, the others are available upon request:

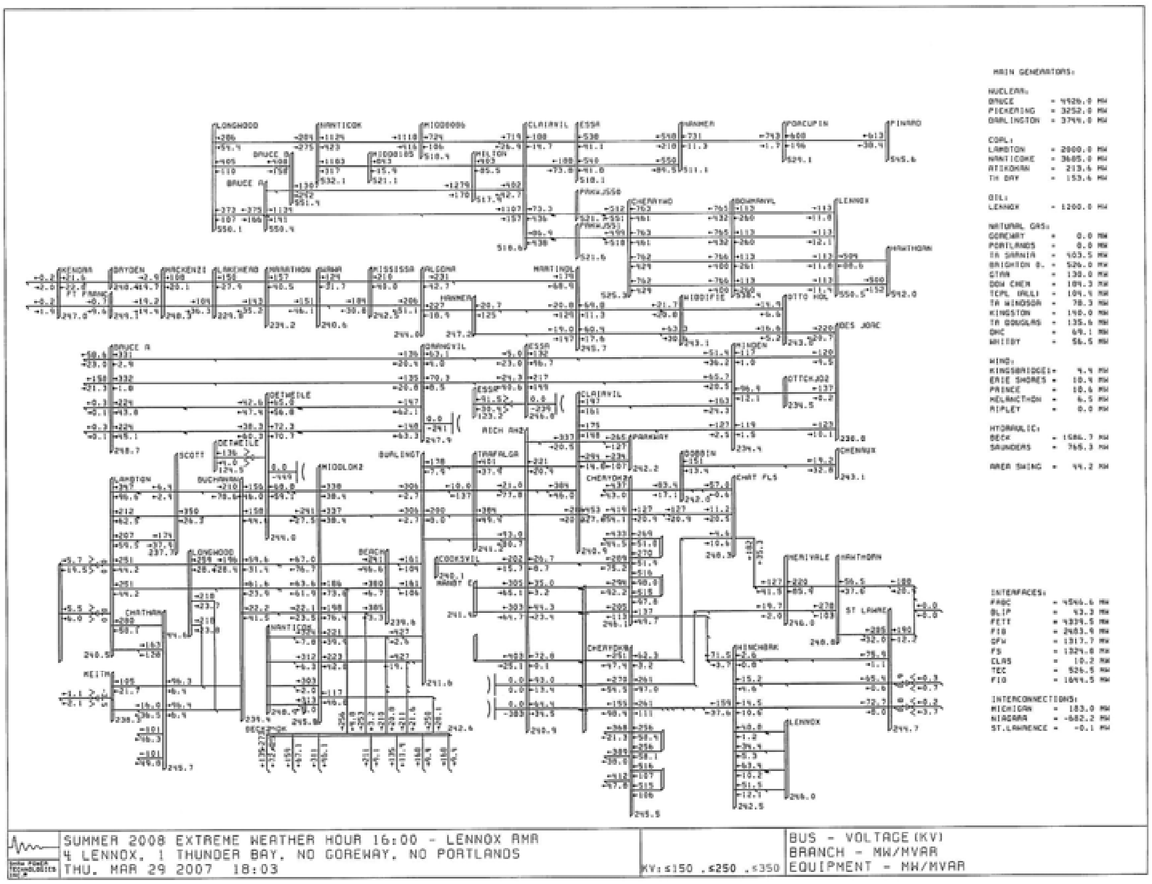

Figure 39: PSS/E simulation - 4 Lennox units

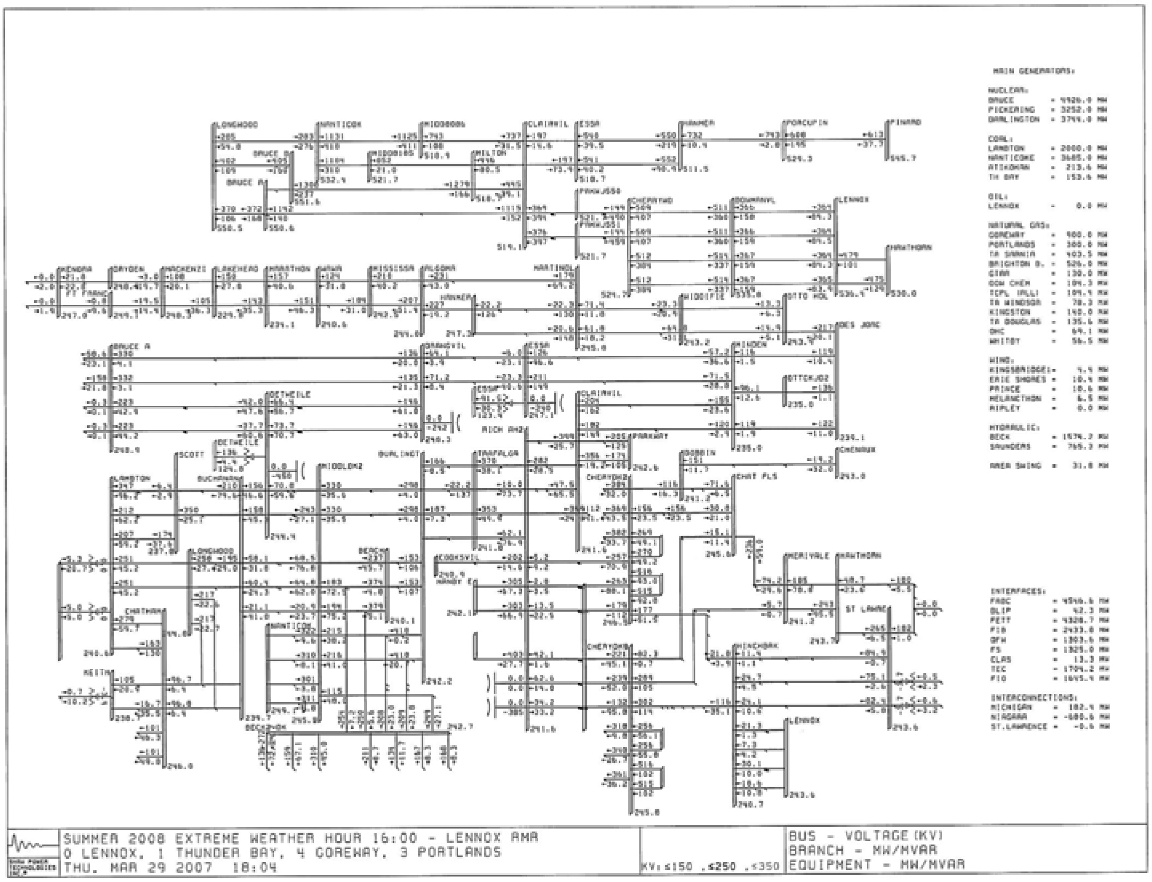

Figure 40: PSS/E simulation - 0 Lennox units

– End of Section –

References

Document Name	Document ID
Lennox GS Deregistration Analysis Oct 2006 – Sep 2007 issue 2.0	

– End of Document –